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CONTROL OF CRITERIA AND NON-CRITERIA POLLUTANTS FROM COAL/OIL MIXTURE COMBUSTION

by

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Coal	Dust	Stationary Sources	21D	11G
Fuel Oil	Aerosols	Coal/Oil Mixtures		07D
Combustion	Chemical Analysis	Particulate	21B	
Boilers			13A	
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ABSTRACT

The report summarizes the existing data base on NO_x, SO_2, and particulate emissions from combustion sources burning coal/oil mixtures (COMs). The need for the U.S. to reduce its dependence on oil and expand its use of coal has prompted a number of industrial and utility energy producers to investigate converting their sites from the exclusive combustion of oil to combustion of COMs. Considerable research has been carried out to demonstrate that COMs represent a viable fuel and that COMs can be pumped and handled compatibly with available equipment and operating practice. However, due to air and water emission standards, long-term utilization of COMs will necessitate some form of emission control techniques to be used on combustion sources.

Under contract to EPA and DOE, Radian has identified and evaluated emission control technologies that could be retrofitted to boilers to control criteria and non-criteria air pollutants. The report also gives emissions data for the trace elements As, Be, Cd, Cr, Hg, Ni, Se, and V. It identifies control techniques that can reduce the emissions of these pollutants. These techniques are assessed for their efficiency to reduce the emissions from COM combustion to levels representative of oil firing. Capital costs, operating expense, and overall lifecycle costs are also discussed.

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CHAPTER 1

INTRODUCTION

The need for the United States to reduce its dependence on oil and expand its use of coal has prompted the Department of Energy (DOE) to take an active role in developing Coal-Oil Mixture (COM) combustion technology. At the present time sufficient technical and economic information has been developed to allow private sector implementation of COM combustion and there are a number of industrial and utility energy producers that are assessing the use of COM at their facilities.

As COM combustion technology becomes more widespread, DOE and the Environmental Protection Agency (EPA) recognize that certain environmental considerations will have to be addressed in order to expand the use of COM in an environmentally acceptable way. Specifically, it will be necessary to determine the potential emissions from sources burning COMs and evaluate, assess and compare the effectiveness of technologies in reducing criteria and non-criteria emissions. Radian Corporation has been under contract to EPA and DOE to conduct a study which has as its objective the identification and assessment of the effectiveness of currently available methods of controlling the release of criteria and non-criteria (trace elements) pollutants from the combustion of COMs.

In order for the reader to become familiar with COM as a boiler fuel, Chapter 2 presents a discussion on the use of COM in existing boilers. Some of the technical and economic factors that determine the suitability of COM as a fuel are presented and boilers that might be candidates for COM conversion are identified. A very important consideration in a COM conversion, the permitting requirements, is highlighted at the end of Chapter 2.

Chapter 3 discusses the emissions that have been measured to date on combustion units burning COM. The criteria pollutant emissions that are discussed are particulate matter, sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). Non-criteria pollutant emissions discussed are the selected trace elements, arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), nickel (Ni), selenium (Se), vanadium (V) and mercury (Hg), as well as the polynuclear organic matter (POM) emissions. Chapter 3 concludes with a discussion of technologies that are applicable to boilers that could be converted to burn COMs. From this broad discussion of control devices, several are selected as most promising for further technical and economic study. These technical and economic evaluations make up the remaining chapters of this report.

Chapter 4 presents the environmental impacts of the technologies selected in Chapter 3. The primary pollutant reduction capability of the technologies are assessed and any secondary environmental impacts are identified and discussed. The potential for multi-pollutant control is also discussed.

The body of the report concludes in Chapter 5 with a discussion of cost impacts. The costs of the technologies discussed in Chapter 4 are described in terms of capital costs, annual operation and maintenance (O&M) costs, annualized costs and cost effectiveness.

Two Appendices are included that present references for all of the emission data discussed in Chapter 3 and the cost basis used to develop the costs included in Chapter 5.

CHAPTER 2

USE OF COM IN EXISTING BOILERS

Rising oil and gas prices, uncertainties in fuel supplies, and proposed government fuel regulations have caused many boiler owners to examine the option of converting their boiler facility from oil/gas- firing to coal-firing. However, conversion to 100 percent coal-firing can be costly, requiring in many cases capital-intensive boiler modifications and the addition of fuel and ash handling equipment. In recent years, a viable alternative to complete coal-firing has surfaced: combustion of coal-oil mixtures (COM). Although the COM combustion concept is more than 100 years old, renewed interest has been sparked by fuel supply and price uncertainty and the desire to maximize use of less expensive domestic fuel - coal. Investigation of the technical and economic aspects of converting existing boilers from oil (or gas) to COM has progressed relatively rapidly in the past few years, and the technology is now on the brink of full-scale commercialization.

Coal-oil mixtures typically consist of anywhere from 20 to 50 percent by weight coal dispersed in oil or in an oil-water mixture (known as COW - coal/oil/water). The coal is usually ground to at least 70 percent minus 200 mesh. A No. 6 heavy residual is typically chosen over lighter distillate oils for COM's; in addition to being less expensive than distillate oil, heavy residual oils reduce coal settling problems with COM relative to lighter oils. Water is sometimes added to the COM as a stabilizer; most commonly the added water ranges from 5 to 20 percent by weight.

The purpose of this study, as stated in the introduction, is to investigate the environmental aspects of COM combustion: what pollutants and in what quantities they are emitted; what is the degree of emission control required and what control techniques are applicable; and what are the environmental and cost impacts of those technologies. As a necessary background to such an analysis this chapter discusses three aspects of converting existing boilers to COM:

- the suitability of COM for existing boilers,
- likely candidate boilers for COM use, and
- environmental regulatory requirements applicable to boilers converted to COM-firing.

The suitability of conversion to COM is dependent on several technical as well as economic factors. Whether a specific boiler is a likely candidate for COM will depend on the age of the boiler (remaining useful life), boiler design, size and capacity factor, geographical location (proximity to COM fuel supply), site-specific boiler modifications required, existing emission control equipment, if any, and emission controls required by the applicable environmental regulations.

2.1 SUITABILITY OF COM FOR EXISTING BOILERS

2.1.1 Technical Factors

There are three basic factors that must be evaluated in determining the technical suitability of converting existing oil- or gas-fired boilers to COM:

- COM fuel properties,
- COM combustion characteristics, and
- boiler modifications required to accommodate COM-firing.

2.1.1.1 COM Fuel Properties

Other than combustion characteristics, the most important COM fuel properties to be considered are viscosity, stability, and abrasiveness.

The viscosity and stability of the COM are interrelated properties: generally, the more viscous the COM is the less tendency there is for fuel instability (settling of coal particles). Thus, factors which increase the viscosity, within pumpability limits, will also tend to enhance COM stability. The results of research and development of COM fuels have indicated the COM viscosity and stability increase with:

- increasing coal content,
- finer ground coal,
- higher oil viscosity, and
- addition of water to the COM.

Also, chemical stabilizing additives have been developed to improve COM stability. These additives are typically emulsifying agents, gelling agents, or surfactants that help keep the coal particles suspended in the oil. Although maximum coal concentration is desirable for economic as well as stability considerations, there appears to be an upper limit of about 60 percent coal in the COM. Beyond this coal concentration pumping and handling difficulties are encountered.[1] Even though 60 percent COM may be possible, COM is typically available ranging from 40 to 55 percent coal in oil. Most of the combustion data is available for this range of concentrations.

The increased abrasiveness of COM relative to oil can potentially cause erosion in pipe bends, pumps, valves, and burners. These potential problems can be minimized through proper material selection, lowered fuel velocities and use of finer ground coal.[2]

2.1.1.2 COM Combustion Characteristics

The major aspects of COM combustion that impact its suitability for existing oil- or gas-fired boilers are listed in Table 2.1-1. As indicated, most of the potential problems can be eliminated or minimized with proper design or only moderate boiler modification.

In general, demonstration tests in both utility and industrial-size boilers have shown that a mixture of up to 50 percent coal can be successfully fired with only relatively moderate boiler modifications - primarily burner modifications and addition of soot blowers. Combustion efficiency, flame characteristics, and carbon burnout with COM have been found to be comparable to firing of No. 6 oil alone.

2.1.1.3 Boiler Modifications

The boiler modifications required in converting from oil or gas to COM are quite site-specific, and depend on such boiler design factors as tube spacing, burner design, furnace size, and bottom ash removal capability.

Boilers that were originally designed for coal-firing and were later converted to gas or oil are ideal for firing COM. Boilers designed for oil-firing commonly have narrower tube spacings than boilers designed for coal, and gas-fired boilers have narrower tube spacings than units designed for oil-firing. The potential exists, in converting to COM, for ash deposition and ash slagging (if the furnace temperature is not maintained below the ash fusion temperature). Bridging of molten ash between the tubes leads to impaired heat transfer and possible boiler derating. Soot blowers will generally be required to prevent these problems; some existing oil-fired boilers have soot blowers, although additional soot blowing capacity may be needed to accommodate COM combustion.

Depending on the existing design, the burners may have to be modified or in some cases, replaced. Most COM combustion studies have found air or steam atomization preferrable to mechanical atomization. The high velocities produced by mechanical atomization combined with the abrasiveness of the COM can lead to significant erosion problems. Even with air or steam atomization, burner tips may need to be made of hardened materials such as tungsten carbide/carbon to minimize erosion.[3] A final consideration in burner design or modification is likely to be the capability to switch from COM- to oil-firing with maximum flexibility.

Combustion of COM requires a larger combustion space relative to oil to allow for the longer residence time needed for complete combustion of the coal particles.[1,4] Depending on the existing furnace volume modifications

TABLE 2.1-1. COM COMBUSTION PROPERTIES IMPACTING CONVERSION TO COM[a]

Combustion Related Area	Potential Problems with COM	Solutions
Heating for atomization	Depending on type of additive, COM stability may deteriorate in the 76 to 93°C (170 to 200°F) range.	Minimize return of heated COM to storage. Careful control and temperatures. Continuous mixing of storage tanks.
Burners	Nozzle erosion may occur with abrasive COM.	Use hardened materials, lower fuel velocities, and air or steam atomization.
Furnace and heat transfer	Lower combustion efficiencies if inadequate furnace area. Potential for ash slagging. Impingement of longer COM flame on furnace wall.	Specific to existing boiler design - extensive modifications required for small furnaces, narrow tube spacing. COM combustion may be feasible without major modification in some existing oil-fired units. Soot blowers required to prevent ash deposition. Coals with high ash fusion temperatures preferrable.

Reference 2.

may be required. In extreme situations (very small furnace) the boiler may not be suitable for COM.

COM combustion will require bottom ash handling capability in most cases. Units designed for oil- and gas-firing do not often have bottom ash removal capability.

In addition to modifications made directly to the boiler, there are other changes to the facility that may be required in converting to COM. The fuel handling system (including pumps, piping, valves, and flow measurement devices) must be adequate to handle the abrasive COM slurry. Also, the more viscous COM will result in greater pressure drops than oil-only and pump capacity or pipe diameter may have to be increased, by modification or replacement, relative to oil-only operation.

Storage tanks for COM received from a centralized off-site preparation plant may have to be modified to include agitators and temperature control.[2] New storage equipment will be required if dual fuel capability (COM and oil) is desired.

2.1.2 Economic Factors

If the technical considerations of converting to COM can be satisfactorily addressed, there are also several economic factors that will impact the desirability of conversion. Although the economics of conversion for a particular boiler may be somewhat complex, particularly for utility applications, the following factors are important in every case:

- capital availability,
- boiler modifications required,
- difference between oil (or gas) and coal prices and the predicted rates of escalation of the fuel costs,
- security of oil or gas supply,
- availability, composition and price of COM,
- boiler size and capacity factor,
- remaining useful life of the boiler, and
- emission controls required.

Each of these factors has a direct effect on the economics of converting to COM, with the difference in oil (or gas) and COM cost playing the major role. The fuel savings realized by converting from oil to less expensive COM must be great enough to offset the capital charges associated with boiler modifications and/or emission controls, at a reasonable return on investment, and to still result in operating cost savings. However, the relative escalation rates of oil and coal prices and the steady and secure availability of oil (or gas) can play a determining role in any such fuel savings calculation. Both escalation rates and supply security are difficult to predict.

On the other hand, the economics of conversion are also affected by the composition of the COM (percent coal, sulfur content and ash content), the COM fuel cost, and the source of the COM (on-site or off-site centralized preparation plant). COM fuel cost is determined primarily by the cost of coal and oil, which account for about 85 percent of the cost on a Btu basis.[5]

Boiler size, capacity factor, and remaining useful life all directly impact the magnitude of the fuel saving realized in converting from oil (or gas) to COM.

The emission controls required by environmental regulations applicable to COM conversions will also be a major factor in the economics of conversion. Regulatory requirements are discussed in Section 2.3, and the costs of alternative emission control options (a prime focus of this study) are presented in Chapter 5.

2.2 CANDIDATE BOILERS FOR COM CONVERSION

The major objective criteria that can be used to describe candidate boilers for COM conversion are:

- existing boiler design and fuel fired,
- boiler size, age, and capacity factor,
- boiler geographical location, and
- applicable environmental regulations.

2.2.1 Boiler Design and Fuel Fired

The boilers most likely to be candidates for COM conversion are (1) those originally designed for coal and now firing oil and (2) those originally designed for and now firing oil. These boilers are the least likely to require extensive modification for conversion to COM-firing. In addition, boilers firing expensive fuel oil have a strong incentive to move away from oil toward less expensive alternate fuels, the supply and price of which may be more stable.

Although boilers firing natural gas or natural gas and oil may also possibly be candidates for conversion to COM, there are some considerations that may make conversion less desirable. First, boilers designed for 100 percent gas-firing are likely to have narrow tube spacing and relatively small furnaces. Conversion to COM would likely require extensive boiler modification or derating of the boiler.[6] Secondly, in certain situations the supply of natural gas may be perceived as being more stable than fuel oil supply. Thus, even though gas prices may continue to rise (especially if complete deregulation occurs) the incentive for converting to COM is somewhat diminished if the natural gas supply is secure. Finally, conversion of gas-fired boilers to COM would almost assuredly trigger PSD review and the associated permitting process. (See Section 2.3 - Regulatory Requirements).

2.2.2 Boiler Size, Age, and Capacity Factor

As discussed earlier, the size, age, and capacity factor of the boiler all play an important role in the economics of COM conversions. Larger boilers with a long remaining useful life and a relatively high capacity factor are the most desireable for COM conversion.

The fuel cost savings realized in converting oil-fired boilers to COM will increase as boiler size increases (for a given capacity factor). Thus, conversion of large utility boilers would result in considerable fuel savings and the economics of conversion are likely to be favorable. However, other factors such as unit availability and capability to meet peak demand with COM are important in evaluating the economics of utility boiler conversion.[5] Conversion of large industrial boilers could also result in large fuel savings and peak capacity or possible derating may be less of a concern. Many experts agree that COM is not economically attractive for boilers smaller than 30 MW (100 x 10^6 Btu/hr).[7] However, the economics of conversion are relatively site-specific and COM may be attractive for some smaller new, high capacity oil-fired units.

The economics of conversion are more favorable for newer boilers than for older units. A minimum of 10 to 20 years remaining life is generally required to make conversion to COM economically justifiable.[9]

Fuel cost savings of COM conversion decrease as boiler capacity factor decreases. Also, the conversion costs on a dollars per heat input (or per unit of steam output) increase as the annual capacity factor decreases. Thus, conversion to COM is less attractive for lower capacity factor boilers. One study found that the costs of COM conversion for a 31,780 kg steam/hr (70,000 lb/hr) industrial oil-fired boiler exceeded the fuel savings once the capacity factor decreased below 20 percent.[8] Once again, however, the conversion economics are dependent on a number of site-specific factors and it is not possible to determine a generalized minimum capacity factor for which COM is attractive.

2.2.3 Boiler Geographical Location

The location of the boiler may play a significant role in evaluating the feasibility of COM conversion, especially for industrial boilers where on-site COM preparation is not economical and COM must be purchased from a centralized preparation plant. On-site COM preparation may be feasible for a large utility conversion and, in fact, one utility in Florida has constructed such a facility.[9]

The geographical distribution of domestic large oil-fired industrial boilers is shown in Figure 2.2-1. Over 80 percent of the boilers are located in Federal Regions 1 through 5, the Eastern and Mid-Western states. New Jersey, New York, and Pennsylvania account for more than 35 percent of the total large oil-fired boilers.[8] These concentrated boiler distributions favor a regional preparation and distribution plant, ideally using existing coal and oil transportation networks.[8]

Table 2.2-1 shows the location of nine operating or proposed centralized COM preparation plants.

2.2.4 Applicable Environmental Regulations

The environmental regulations applicable to COM conversion will vary with boiler size and boiler location (i.e. attainment or non-attainment area). The degree of emission control required by the regulations and the presence of existing emission control equipment may have a determining effect on the desireability of conversion to COM. If the applicable regulations dictate the retrofit of post-combustion flue gas cleaning devices, the capital and operating costs of the devices must be factored into the COM conversion economics. Also, the availability of land for the control devices must be considered. The regulatory requirements for COM conversion are discussed in more detail in the following section.

2.3 REGULATORY REQUIREMENTS FOR COM CONVERSION

Conversion of existing oil-fired boilers to COM-firing may be subject to a variety of environmental regulations relating to air emissions and liquid and solid waste discharges. In general, liquid and solid waste discharge and disposal will be governed by federal or state regulations applicable to coal- and oil-fired boilers. Conversion to COM will result in increased amounts of solid waste - bottom ash, fly ash, and if post-combustion SO_2 control is required, solids from flue gas desulfurization processes - relative to oil-firing. However, all these solid wastes have been designated as "non-hazardous" by EPA, and environmentally acceptable methods of disposal do exist. Liquid waste regulations applicable to COM conversion are the effluent limitations established through (NPDES) permits.

Determining the applicable air emission regulations, and associated permitting and review processes, is somewhat more complex. The remainder of

Region	No. of Combustors	Capacity in Megawatts
1	140	2,592
2	382	4,134
3	277	5,553
4	239	4,757
5	226	4,388
6	55	1,358
7	19	270
8	43	701
9	25	469
10	25	476
Total	1,431	24,698

Federal Regions

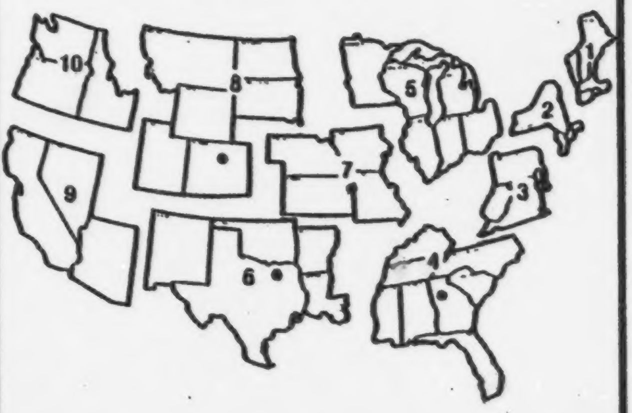

Figure 2.2-1. Regional distribution of oil-fired industrial boilers. (>30 MW (100 x 10^6 Btu/hr).[8]

TABLE 2.2-1. INSTALLED AND ANNOUNCED DOMESTIC COM PLANTS[a]

UNIT	LOCATION	STABILIZATION	BPD	CONSTR.	OPER.
INSTALLED					
Nepsco	Salem Harbor, MA	Chem.	2,000	1978	1979
CoaLiquid	Shelbyville, KY	Cottell	1,500	1978	1979
Florida Power & Light	Sanford, FL	Chem.	10,000	1979	1980
Ergon	Vicksburg, MS	Ultrafine	5,000	1980	1980
ANNOUNCED					
Ashland Oil	Southpoint, OH	Chem.	1,200	1980	1981
COMCO	Bartow, FL	Ultrafine	3,000	1980	1981
Island Creek Coal	Jacksonville, FL	Chem.	3,000	1981	1981
CoaLiquid	Jacksonville, FL	Cottell	6,000	1981	1982
Mt. Airy	Dravosburg, PA	Cottell/Chem.	1,500	1981	1982
Belcher	Mobile, AL	Chem./Mech.	5,000	1981	1982
Wyatt	New Haven, CT	Chem./Fine	3,000	1981	1982
Amcom	Chester, PA	N/A	3,000	1981	1982
Arco	West Virginia	Chem.	5,000	1981	1982

CUMULATIVE COM CAPACITY -BPD

ACTUAL		
1979	-	3,500
1980	-	18,500
FORECAST		
1981	-	25,700
1982	-	49,200

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[a] Reference 1.

this section will focus on the air regulations that could potentially govern conversion of existing oil-fired boilers to COM (Sections 2.3.1 to 2.3.3) and on conversion from gas-firing to COM (Section 2.3.4).

Conversion to COM could potentially be affected by three Clean Air Act (CAA) programs:

- new source performance standards (NSPS)
- prevention of significant deterioration (PSD)
- nonattainment review (NA).

These sets of regulations are currently in effect and were initially administered by the U. S. Environmental Protection Agency (EPA). In the past year, certain states have also been granted authority by EPA to administer the PSD regulations. Most states now administer the NSPS program as part of their permit review process.

2.3.1 New Source Performance Standards (NSPS)

Under the recently promulgated NSPS (40 CFR 60, Subpart Da - June 1979) for steam electric generating units, conversion of existing oil-fired boilers to COM would be exempt from the NSPS.[10] The 1979 NSPS, which in effect requires FGD and a fabric filter or an electrostatic precipitator on all new utility boilers, specifically exempts conversions of boilers originally designed to fire oil or gas to other fossil or non-fossil fuels [40 CFR 60 (40)(a)].

No NSPS has been promulgated for industrial boilers with heat input capacities of less than 73 MW (250 x 10^6 Btu/hr). Large industrial boilers (>73 MW) not meeting the criteria of an electric utility are subject to NSPS promulgated in 1971.[12] [40 CFR 60, Subpart D]. Although the 1979 NSPS for utility units amended this Subpart, the amendment did not affect large industrial boilers. Fuel conversions are addressed in the general NSPS provisions [40 CFR 60 14(e)(4)] by exemption of forced coal conversions and conversions of sources that could accommodate an alternate fuel prior to the 1971 promulgation.[13]

2.3.2 Prevention of Significant Deterioration (PSD)

As the name implies, the PSD program is aimed at preventing deteroriation of air quality that might occur from unregulated new or modified sources of air pollutants. The relatively lengthy and complex process of PSD review, which can take up to between 12 and 24 months, has the following requirements:

- control technology review,

- air quality review,
- air quality monitoring, and
- development of detailed source information.

Also, in some cases, visibility impact analyses and growth impact analyses must be performed.

If the source is subject to PSD review, the source must apply "Best Available Control Technology" (BACT). The owner of the source is required to evaluate environmental, energy, and economic impacts of selected and alternative control techniques. The BACT analysis must include information on emission rates and control equipment to be used. Determination by the regulatory agency of BACT is based on applying a technology at least as efficient as the technology which serves as the basis for any NSPS applicable to the source. In some cases, state or local agencies may determine that BACT is a technology that is more efficient than the one upon which NSPS is based.

Under the current PSD regulations [40 CFR 52, August 7, 1980] all "major new or modified sources" of air pollutants regulated under the CAA (including SO_2, PM, and NO_x) must be reviewed by EPA or by the state (if review authority has been granted to the state).

There are several key definitions important in determing the applicability of PSD regulations to COM conversions. First, only major sources are subject to the PSD regulations. A major new or modified source is defined as one which:

(a) is in any one of 28 major source categories and which has the potential to "emit" 100 tons per year or more of any criteria pollutant (PM, SO_2, NO_x, CO, hydrocarbons, or lead), or

(b) is any other stationary source that has "the potential to emit" 250 tons per year or more of any criteria pollutant.

Secondly, modification of a major source is subject to PSD review if the physical change or change in the method of operation results in a significant net emissions increase of any criteria pollutant from the source.[14] The same includes the COM boiler as well as all other emission points within the same industrial plant. A net emissions increase is significant if it exceeds the de minimus levels set by EPA. The de minimus levels for the pollutants of primary concern in COM conversions are:

- PM: 25 tons/yr,
- SO_2: 40 tons/yr, and
- NO_x: 40 tons/yr.

Finally, "potential to emit" refers to the emissions from the source, at maximum design capacity, after application of any emission controls.

Thus, for a COM conversion to be exempt from PSD review the boiler, including its parent facility, must (1) not be a major source for any criteria pollutant or (2) the conversion must result in a net emissions increase below de minimus levels, including contemporaneous emission reductions from elsewhere within the plant.

With regard to the first exemption criteria, fossil fuel-fired steam electric generators and fossil fuel-fired industrial boilers with a heat input capacity of 73 MW (250 x 10^6 Btu/hr) or greater are listed among the 28 major sources categories. In addition, these boilers have the "potential to emit" greater than 100 tons/yr of at least one criteria pollutant - SO_2. For a 73 MW oil-fired boiler firing even very low sulfur oil (0.3 percent sulfur) annual SO_2 emission, based on maximum design capacity, would be about 350 tons/yr. [PM emissions would be about 110 tons/yr and NO_x emissions (based on 0.3 percent nitrogen fuel) would be about 440 tons/yr]. Annual emissions would be greater for boilers larger than 73 MW.

Industrial boilers with heat input capacities of less than 73 MW are not listed in the 28 major source categories. However, depending on the sulfur content of the oil-fired and the boiler size, some small oil-fired industrial boilers may be major sources because SO_2 emissions exceed 250 tons/yr. Figure 2.3-1 shows annual SO_2 emissions, at maximum capacity, as a function of boiler size and fuel sulfur content. This figure indicates that for boilers larger than about 14.7 MW (50 x 10^6 Btu/hr), a low sulfur oil must be burned for the boilers to meet the 250 tons/yr major source exemption criteria. Even if boiler emissions are below 250 tons/year, the plant at which the boiler is located may exceed this level. In such cases, the boiler can still be subject to PSD review.

Thus, most oil-fired boilers that are candidates for conversion to COM are unlikely to be exempt from PSD review under the first exemption criterion. Therefore, the second criterion of net emissions increase must be evaluated carefully. As shown in the following calculations, the de minimus levels have been set low enough that emissions from COM, excluding any intra-source reductions, essentially have to be no greater than oil-only levels to avoid PSD review.

The allowable net emissions increase in converting from oil to COM can be calculated as:

$$\text{Allowable increase (lb/}10^6\text{ Btu)} = \frac{\text{(D.M.)(2000 lb/ton)}}{\text{(Q)(8760 hr/yr)}}$$

where D.M. = De Minimus levels (ton/yr)
Q = Boiler size (10^6 Btu/hr)

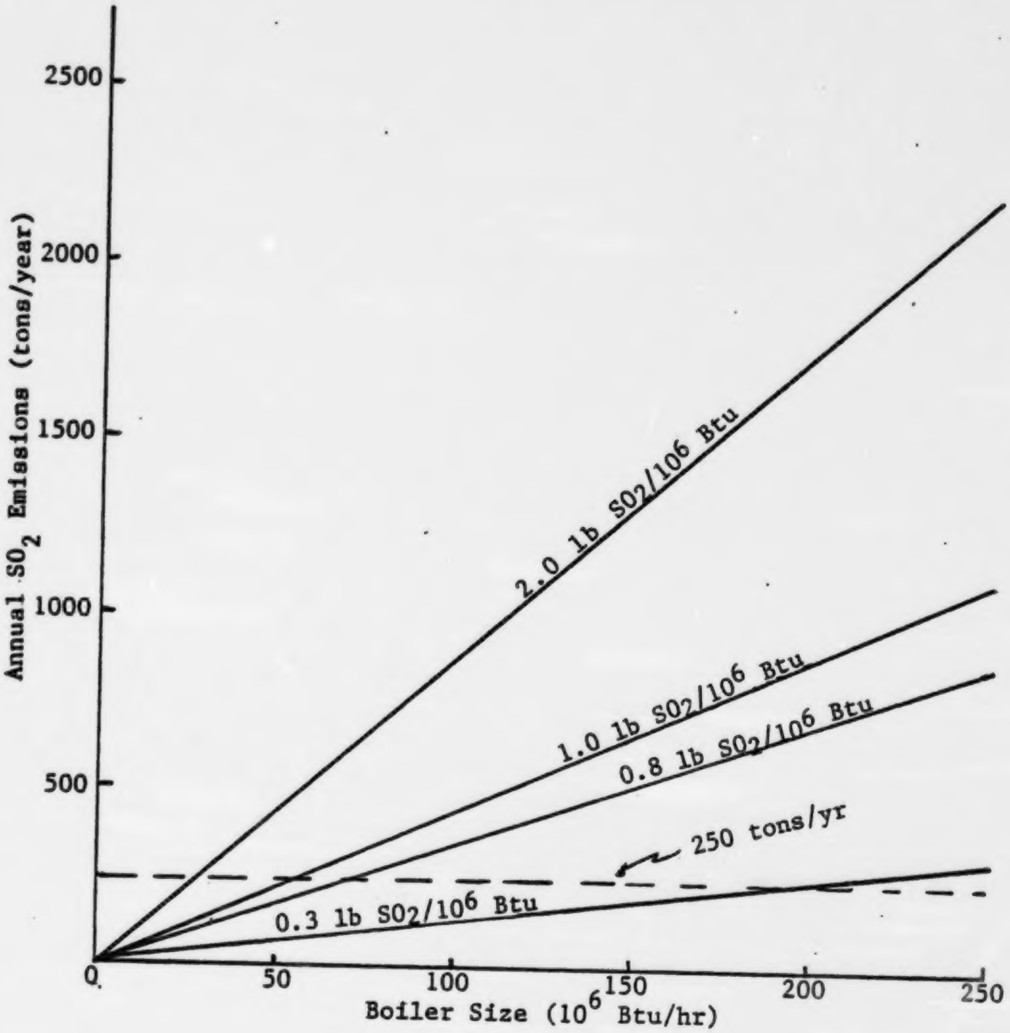

Figure 2.3-1. "Major Source" criteria for boilers less than 73 MW (250 x 10^6 Btu/hr).

For example, for a 73 MW (250 x 10^6 Btu/hr) boiler SO_2 emissions could increase by only 17.2 ng/J (0.04 lb/10^6 Btu) in converting from oil to COM to avoid exceeding de minimus levels:

$$\frac{(40\ \text{tons/yr})(2000)}{(250)(8760)} = 0.04\ \text{lb}/10^6\ \text{Btu}$$

Allowable increases (on a heat input basis) would decrease as boiler size increases, but they would be slightly greater for smaller boilers:

$$\frac{(40\ \text{tons/yr})(2000)}{(100)(8760)} = 0.09\ \text{lb}/10^6\ \text{Btu}$$

The surest way to be exempt from PSD is for SO_2, PM, and NO_x emissions from COM to be no greater than oil-only emissions prior to conversion. It should be noted that net emissions increases are calculated based on actual emissions before modification, so if the boiler fired very low sulfur distillate oil or natural gas it may be infeasible to reduce the net emissions increase below de minimus levels.[10]

The emissions from oil-only combustion before COM conversion will depend in many cases on the state regulations applicable to existing oil-fired boilers. These regulations are specified in State Implementation Plans (SIPs). The current SIP's applicable to existing oil-fired units are shown in Table 2.3-1 for several states. The SO_2 regulations were obtained from an EPA summary (Reference 15). Particulate matter and NO_x regulations were obtained from the most recent SIP versions given in Reference 16.

2.3.3 Special Cases

Although the previous discussion of PSD review requirements is likely to apply to most COM conversions, the applicable environmental regulations in "nonattainment areas" may be different.

The 1977 Amendments to the CAA established a regulatory plan for certain areas of the country that are not in compliance with the National Ambient Air Quality Standards (NAAQS) for criteria air pollutants. In these designated nonattainment areas, there are preconstruction review requirements beyond the PSD requirements described above. In effect, offsetting emissions reductions, equivalent to the increase in emissions from regulated source, must be obtained. These offset requirements apply to each pollutant for which the area is designated to have a nonattainment status. Emissions offsets are generally achieved by installing improved controls on existing sources in the vicinity of the affected source.

In California, the major urban areas are nonattainment for several pollutants. San Francisco, San Diego, and Los Angeles are nonattainment for ozone, CO, and particulates; Los Angeles and San Diego are nonattainment for NO_2; and Los Angeles is nonattainment for SO_2. Since SO_2 and NO_x emissions

TABLE 2.3-1. SIP REGULATIONS FOR EXISTING OIL-FIRED BOILERS FOR CERTAIN STATES[a,b]

State	SO_2	PM	NO_x
California	All sizes: Varies from 300 to 2000 ppm SO_2 depending on location; some locations: 0.5% S fuel limit.	10 lb/hr or .1 gr/scf generally; varies by location.	All sizes: 225 ppm (also varies by location).
Florida[c]	< 250: "Reasonably available controls" > 250: 1.1 lb/10^6Btu some counties; 2.75 lb/10^6Btu other counties.	> 250: 0.1 lb/10^6 Btu < 250: BACT	> 250: 0.3 lb/10^6 Btu < 250: BACT
Illinois	All sizes: 1.0 lb/10^6Btu > 250: 0.8 lb/10^6Btu (after 4/72)	All sizes: 0.1 lb/10^6Btu	> 250: 0.3 lb/10^6Btu < 250: No regulation
Indiana	< 24: 6.0 lb/10^6Btu 24 to 3081: 6 to 1.2 lb/10^6Btu[f,g]	All sizes: 0.1 lb/10^6Btu	No regulation
Kentucky	2.0 to 2.5 lb/10^6Btu depending on size.[e] Also may vary with location.	Varies widely depending on boiler size, location.	No regulation
Maryland[d]	All sizes: 1 to 2% S fuel depending on location.	All sizes: $E = 1.026(I)^{-0.233}$ (before 1972) 25–250: $E = \log_{10}[6.597(I)^{-0.3}]$ (after 1972). > 250: 0.1 lb/10^6Btu (after 1972)	
Massachusetts	0.28 to 2.2 lb/10^6Btu depending on location and size.[f]	All sizes: 0.12 to 0.15 lb/10^6Btu	

TABLE 2.3-1. (Continued). SIP REGULATIONS FOR EXISTING OIL FIRED BOILERS FOR CERTAIN STATES[a,b]

State	SO_2	PM	NO_x
New Jersey	0.3% S fuel (May be higher in some locations	<250: 0.25 to 0.15 lb/10^6Btu[f] >250: 0.1 lb/10^6Btu	No regulation
New York	0.3 to 2.0% S fuel depending on location.[f]	<250: 0.2 lb/10^6Btu >250: 0.1 lb/10^6Btu	<250: 0.3 lb/10^6Btu >250: No regulation
Pennsylvania	0.3 to 3 lb/10^6Btu depending on location and size.	50: 0.4 to 0.1 lb/10^6Btu >600: 0.1 lb/10^6Btu	No regulation No regulation

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[a] SO_2 regulations from Reference 15 ; PM and NO_x from Reference 22 .

[b] Boiler sizes listed in 10^6Btu/hr; Emission limits listed in lb/10^6Btu.

[c] BACT: "Best Available Control Technology"; SO_2 standard applies to entire plant, not just one source.

[d] PM regs: vary by year of construction
E = lb/10^6Btu allowable emissions
I = boiler heat input capacity, 10^6Btu/hr.

[e] Emission limit decreases as boiler size increases.

[f] Applies to entire plant.

[g] Sources also subject to air quality regulation.

are precursors to ozone, each of the areas is subject to the nonattainment regulations for that pollutant.[17] Thus, if emissions of NO_x are increased in converting a boiler to COM firing, control equipment must be installed to reduce COM emissions to the level of emissions from the fuel fired before conversion. If such a reduction is not achievable, then emission reductions (offsets) from other sources must be developed to comply with the "no net increase" requirement of California's SIP.[17]

One source suggests that NO_x offsets in major California urban areas are not available for "projects of any significant size."[17] In such a case, the offsets will likely have to be generated by decreased fuel consumption.

Since PSD and NA regulations apply to the entire plant where the boiler being converted to COM is located, reductions in emissions within the plant can be credited against the emissions increase in switching from oil to COM. However, the decision, for example, to reduce SO_2 emissions by burning lower sulfur fuel in another boiler will depend primarily on fuel prices and availability and boiler capacity factors. Any evaluation of the most technically and economically desireable scheme for COM conversion at multi-boiler plants would have to be on a site specific basis.

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CHAPTER 3

COM EMISSIONS AND CONTROL OPTIONS

This chapter discusses the nature and magnitude of uncontrolled air emissions from COM combustion and the technologies available to control these emissions. In most cases where an existing oil-fired boiler is to be converted to COM combustion, the uncontrolled emissions of particulate matter (PM), and nitrogen oxides (NO_x) will be greater for COM-firing than for oil-firing. The increased air emissions result from the contribution of coal ash and nitrogen to the combustion emissions. Emissions of SO_2 from COM combustion may be less than or greater than oil-only SO_2 emissions, depending on the relative sulfur contents of the COM and the oil. Trace elements emissions (except nickel and vanadium) from COM combustion may also be greater than those for "oil-only" firing.

Sections 3.1 through 3.4 of this chapter summarize the available PM, SO_2, NO_x, and trace element emission test data for COM combustion. Section 3.5 discusses organic emissions from COM combustion.

Section 3.6 provides a brief review of the emission control technologies applicable to COM-fired boilers. Basically, the applicable technologies are those currently in use on existing oil- and coal-fired boilers. Some newer technologies, still in the developmental or demonstration stage, may also be applicable to COM units. Based on certain general criteria, such as the status of development, demonstrated effectiveness, use on existing oil- or coal-fired boilers, retrofit suitability, and multipollutant control capability, several technologies are selected for further evaluation of their environmental, and cost impacts for COM-fired boilers. (Those impacts are presented in subsequent chapters of this report.)

3.1 PARTICULATE MATTER (PM) EMISSIONS

Measured emissions of PM (fly ash) from boilers firing COM are a function of the ash content of the COM and, to some degree, the amount of ash deposition in the boiler. Since the ash content of residual oil is negligible when compared to the ash content of coal, the COM ash content is primarily dependent on the coal ash content and the percentage of coal used in preparing the COM. Although the majority of test data suggest that most of the COM ash (80 to 90+ percent) is emitted as fly ash, some COM combustion tests have shown significantly lower fly ash emissions. Ash deposition in the boiler may be the cause of the reduced measured PM emissions.

The existing data base on PM emissions from COM combustion is somewhat limited. Most of the available data are for industrial units with steam capacities of 54,480 kg/hr (120,000 lb/hr) or less. Only a few PM emission measurements have been made on utility boilers firing COM. The following discussion presents the available data on mass emissions, opacity, and fly ash particle size for COM combustion. The mass emission data are presented on a ng/J (lb/10^6 Btu) heat input basis. In some cases, the ng/J (lb/10^6 Btu) values were taken directly from the literature source. However, many references gave PM emission data only in concentration (gr/scf) or lb/hr units. Concentration data were converted to ng/J (lb/10^6 Btu) using a weighted "F-factor".[1] Data reported in lb/hr were converted to lb/10^6 Btu by dividing by reported Btu of heat input (when possible) or by dividing by heat input estimated from steam output. References for the emission test data used in this section are listed in Appendix A.

3.1.1 Mass Emissions and Opacity

Figure 3.1-1 shows the range and average of uncontrolled PM mass emission data for seven boilers firing COM. Uncontrolled emissions from firing the constituent oil are shown for comparison for three of the sites. Most of the data were collected by EPA Method 5.

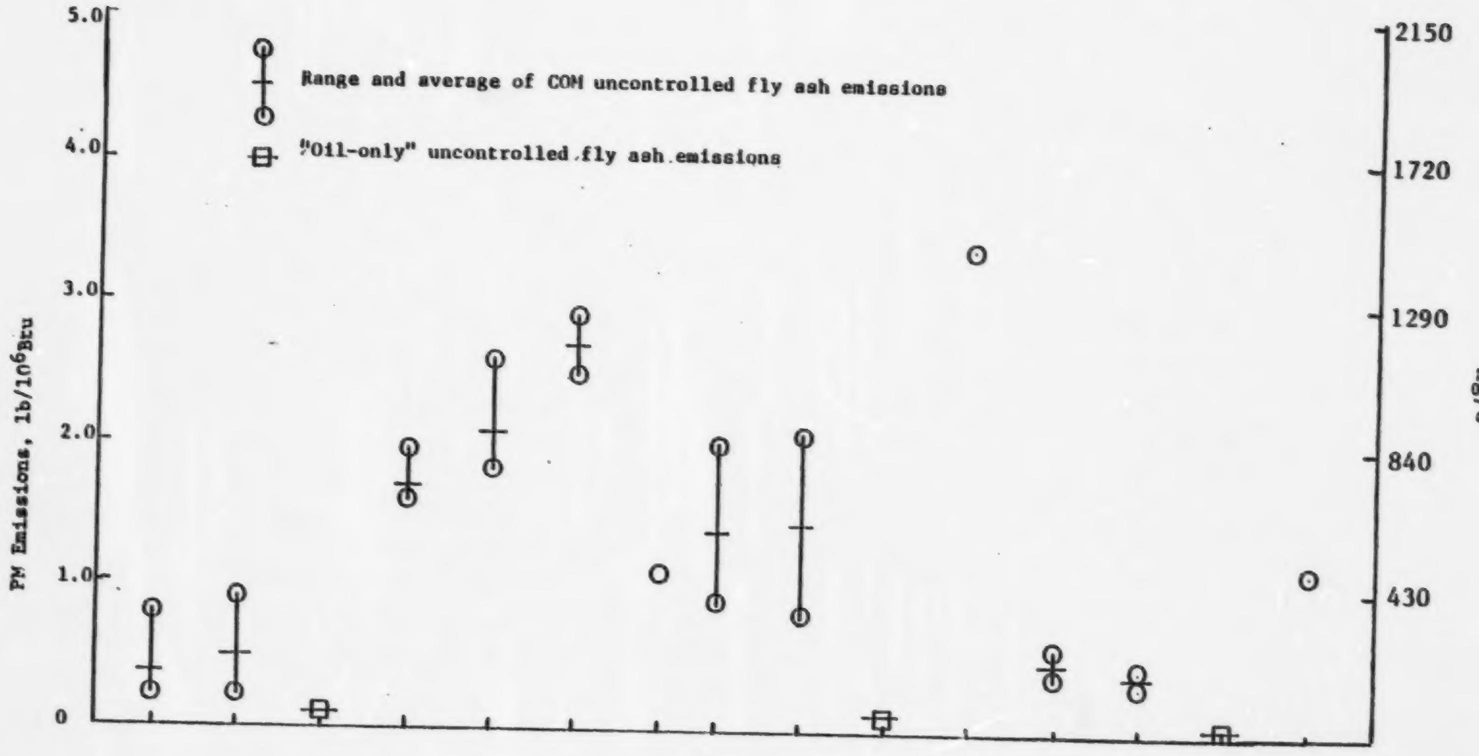
Average uncontrolled emissions from COM combustion were greater than 430 ng/J (1.0 lb/10^6 Btu) in eight of twelve test series. Emissions from oil-only combustion were less than 43 ng/J (0.1 lb/10^6/Btu) in each of the three tests.

Fly ash deposition in the boiler may account for the relatively low emissions at Site A.2. And the reference for Site A.19 (Reference 7) stated that "significant ash deposition" was observed during the COM testing.

Three different grinds of coal (fine, medium, and coarse) were used to prepare the COMs tested at Site A.4. Figure 3.1-1 shows the coarse ground coal COM to have the highest PM emissions, followed by the medium ground coal COM, with the fine ground coal COM having the lowest measured uncontrolled emissions.

Except for Sites A.2, A.5, and A.19, the data indicate a general trend of increasing fly ash emissions with increasing coal ash content. Figure 3.1-2 is a plot of the average PM emissions as a function of average coal ash content. Excluding the coarse and fine ground coal COM data at Site A.6 and excluding Site A.5, two least squares lines were fit to the remaining four data averages. One fit was forced through the origin, the other was not. These curves are only approximations of PM emissions as a function of COM ash content, but they do indicate that a substantial portion of the COM ash is emitted as fly ash.

Figure 3.1-3 also supports this conclusion. About 80 percent of the total COM ash was emitted as fly ash in COM combustion tests in a 400 MWe utility boiler.



SITE	A-2	A-2	A-2	A-4	A-4	A-4	A-5	A-6	A-6	A-6	A-11	A-19	A-19	A-19	A-20
COM composition															
%coal	20	30	-	41	41	42	40	35	35	-	50	20	20	-	50
%oil	80	70	100	59	59	58	60	60	60	100	30	80	73	100	40
%water	-	-	-	-	-	-	-	5	5	-	20	-	7	-	10
COM, % ash	1.3	2.1	0.13	3.3-3.5	3.2-3.7	3.0-3.5	5.7	2.5	2.5	0.1	4.7	1.6	1.6	-	2.7
Footnote	a	a	a	b	c	d	e	f	f	f	g	h	h	h	i
No. of Points	6	3	6	4	4	4	1	6	6	3	1	7	4	4	1
Opacity, %	7-19.5		2-4	←23-28→				← 32-35→							

Figure 3.1-1. Uncontrolled PM emission data from COM combustion.

FOOTNOTES FOR FIGURE 3.1-1

[a] Tests conducted in 100 hp firetube boiler. PM emissions measured by "isokinetic stack sampling." Emissions (lb/10^6 Btu) estimated, using weighted "F-factor" method, from data reported as gr/scf and from reported flue gas O_2 data. Emissions from COM appear too low, indicating possible ash deposition in the boiler. Opacity, measured simultaneously with transmissometer (Reference 2).

[b] Tests conducted in 700 hp watertube boiler. PM emissions measured by isokinetic stack sampling. Emissions (lb/10^6 Btu) calculated by dividing reported lb/hr PM by reported heat input (10^6 Btu/hr). COM made from finely ground coal [92%-325 mesh; 20 μm average particle size]. Opacity measured simultaneously by transmissometer (Reference 3).

[c] Same as b, except COM made from medium grind coal (86%-200 mesh; 42.1 μm average particle size).

[d] Same as b, except COM made from coarse grind coal (60%-200 mesh; 67.0 μm average particle size).

[e] Tests conducted in 700 hp watertube boilers. PM emissions measured by EPA Method 5; reported in lb/10^6 Btu. (Reference 4).

[f] Tests conducted in 120,000 lb steam/hr boiler. COM compositions shown are estimated average; composition varied during tests. PM measured by EPA Method 5. PM emissions (lb/10^6 Btu) estimated from reported lb/hr PM and steam flow assuming 1100 Btu/lb steam, condensate return @ 10 psig, and 80 percent boiler efficiency. Opacity measured with a "Barley Smoke Meter". (Reference 5).

[g] Tests conducted in 10,000 lb steam/hr firetube boiler. Emissions measured by EPA Method 5; reported as lb/10^6 Btu. COM (COW) contains 8% No. 4 oil, 22% No. 6 oil, 50 percent coal, and 20% H_2O. (Reference 6).

[h] Tests conducted in 150 hp horizontal firetube boiler operated @ ½ load. PM emissions measured by EPA Method 5; reported as lb/10^6 Btu. No. 4 oil used to make COM. Reference cited significant ash deposition in boiler", indicating that PM emissions may be lower than expected. (Reference 8).

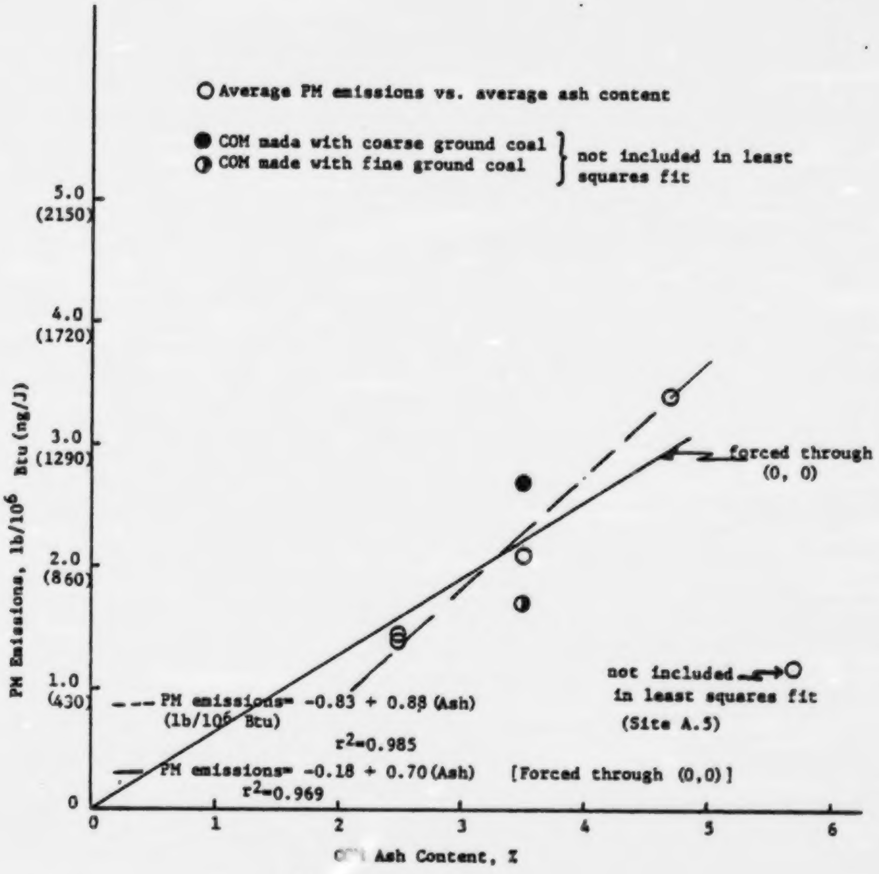


Figure 3.1-2. COM PM emissions as a function of COM ash content. (Data from Sites A.4, A.5, A.6, A.11 - average emissions).

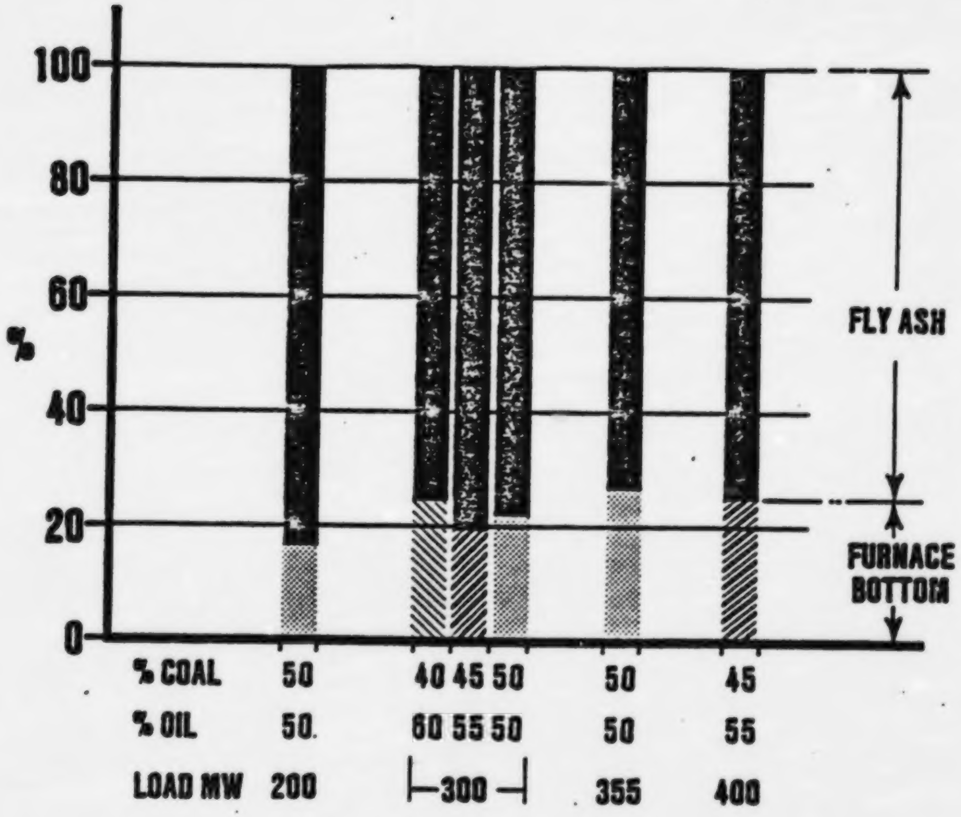


Figure 3.1-3. Total ash distribution between bottom ash and fly ash for COM combustion in a utility boiler - Site A.14. (Reference 9).

Figure 3.1-4 illustrates the trend of increasing PM emissions with increasing coal percentage in the COM (i.e. increased COM ash content). Uncontrolled emissions from combustion of a 15 percent coal COM in a 383 MWe utility boiler were about 151 ng/J (0.35 lb/10^6 Btu). For the same unit, uncontrolled emissions from combustion of a 37 percent coal COM were about 430 ng/J (1.0 lb/10^6 Btu). [The emissions from this site appear to be relatively low, considering the COM ash content and the data in Figures 3.1-1 through 3.1-3. Ash deposition in the boiler may be the cause.]

Transmissometer opacity data, taken simultaneously with mass emission data at Site A.4 (Figure 3.1-1), ranged from 23 to 28 percent. Similar results were obtained at Site A.6, where the opacity ranged from 32 to 35 percent. The relatively lower opacities at Site A.2, which were also measured simultaneously with mass emission data, may be the result of the relatively lower mass emissions at that site.

3.1.2 COM Fly Ash Particle Size Distribution

Figures 3.1-5 and 3.1-6 show particle size distribution of fly ash from COM combustion. Both sets of data were collected with cascade impactor sampling methods.

The data in Figure 3.1-5 show that the fly ash emissions from combustion of COM made with finely ground coal tend to be smaller than emissions from COM made with medium or coarse ground coal. [These data were obtained during combustion tests of a 40 percent coal COM.]

Figure 3.1-6 shows that most of the fly ash emissions from Site A.6 were less than 10 micrometers in diameter and microscopic examination of the impactor catch showing that 70 percent of the particles were less than 15 micrometers. (Reference 5).

Other particle size data, shown in Table 3.1-1, which were collected with the Source Assessment Sampling System, indicate that about 50 percent of the particulate matter from COM combustion was less than 10 micrometers in diameter. The data in Table 3.1-1 indicate that there is not a significant difference in the particle size distribution of COM fly ash at Site A.5 and that of fly ash from coal/oil/water mixtures at Site A.11.

By comparison, the fly ash particles generated from residual oil-firing are almost all less than 10 micrometer in diameter, and the majority of particles fall in the less than 3 micrometer size range.[11,12]

3.2 SULFUR DIOXIDE (SO_2) EMISSIONS

The SO_2 emissions from COM combustion are a direct function of the fuel sulfur content. The COM sulfur content is in turn determined by the sulfur contents of the coal and oil used to make the COM and their relative percentage in the COM. At least 95 percent of the fuel sulfur is typically

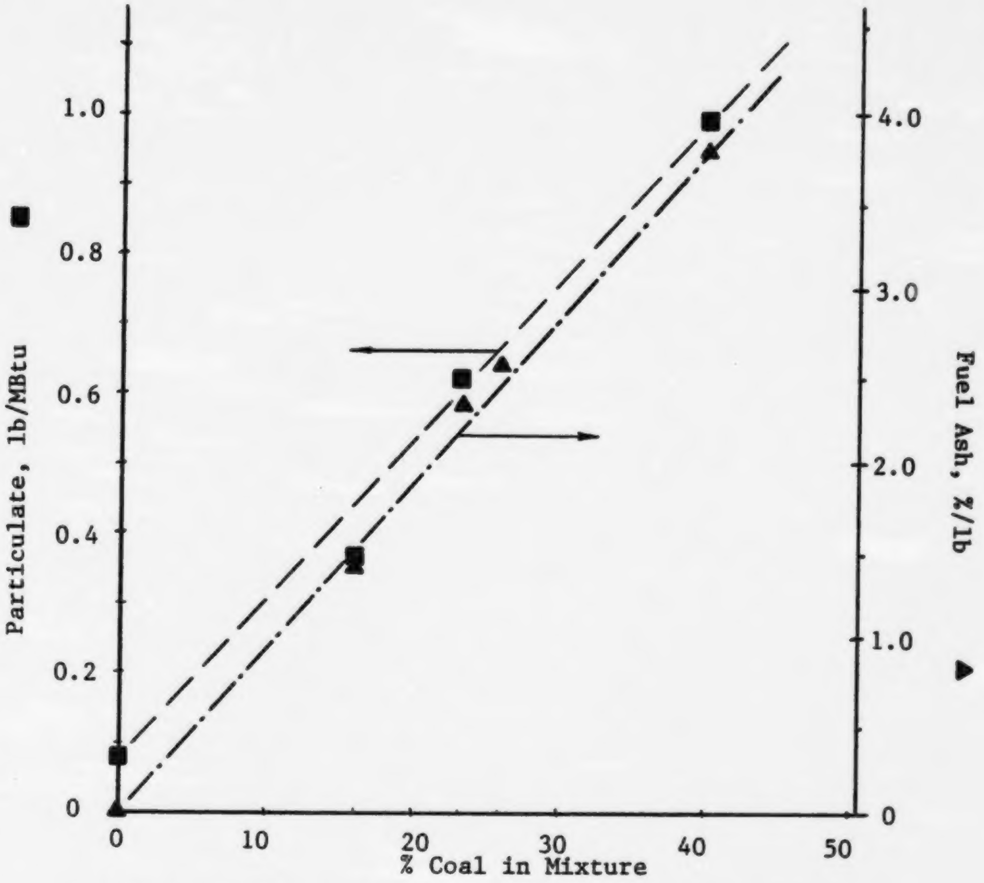
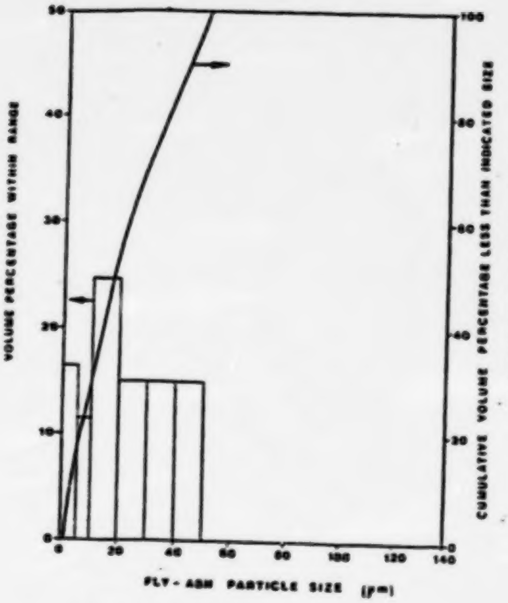
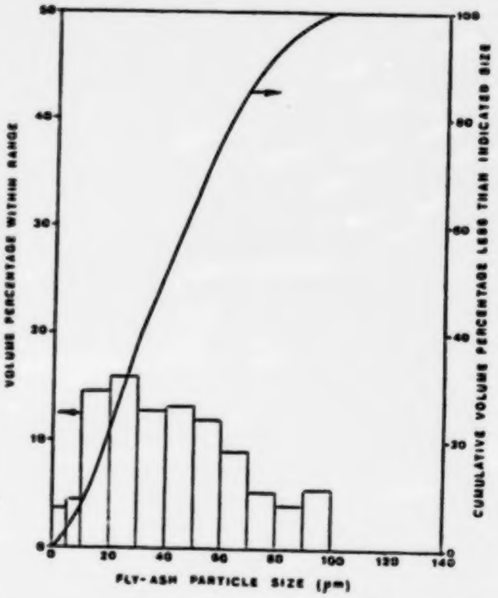


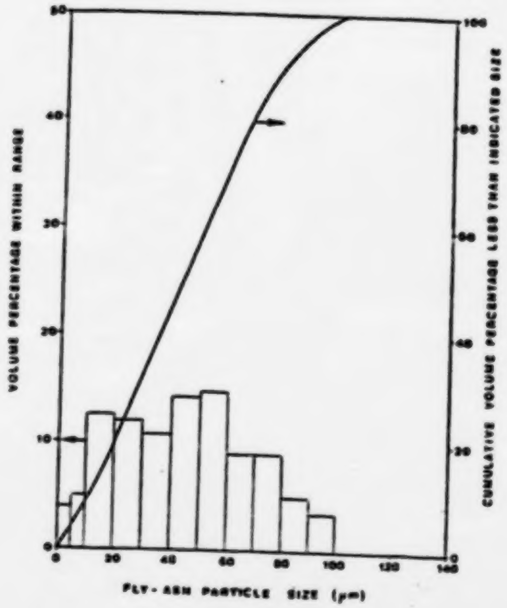
Figure 3.1-4. PM emissions from COM combustion in a 383 MW utility boiler (originally designed for coal) - Site A.13. (Reference 10).



PARTICLE SIZE DISTRIBUTION OF FLY ASH FOR TEST NO. 2
(FINE COAL)



PARTICLE SIZE DISTRIBUTION OF FLY ASH FOR TEST NO. 5
(MEDIUM COAL)



PARTICLE SIZE DISTRIBUTION OF FLY ASH FOR TEST NO. 8
(COARSE COAL)

Sampling Method:
Andersen Cascade or Sierra
Impactor

COM: 40% coal
60% oil
3.0-3.7 % ash

Fine coal: 92% - 325 mesh
(20.6 μm avg.)

Medium coal: 86% -200 mesh
(42.0 μm avg.)

Coarse coal: 60% -200 mesh
(67.0 μm avg.)

Figure 3.1-5. Particle size distribution of fly ash from COM combustion. Site A.4. (Reference 3).

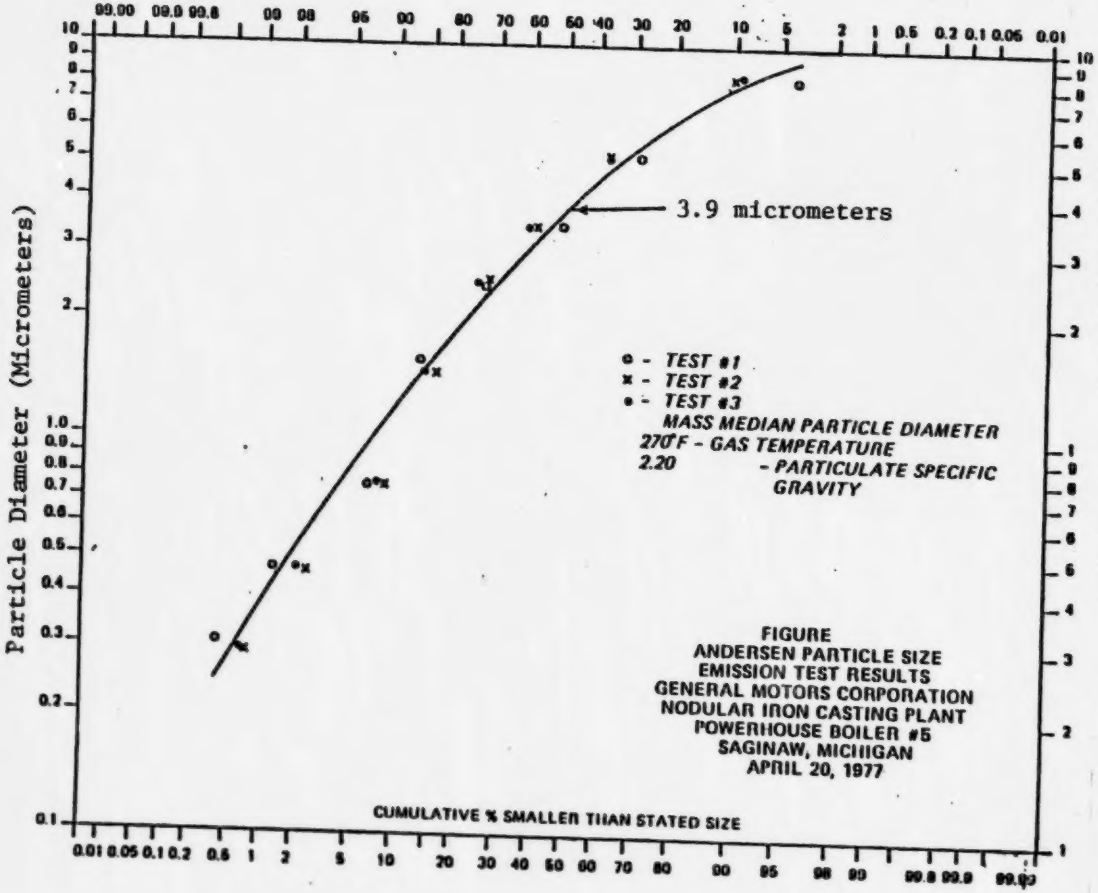


Figure 3.1-6 Particle size distribution of fly ash from COM combustion - Site A.6. (Reference 5).

TABLE 3.1-1. OTHER PARTICLE SIZE DATA

Site	COM Composition	Particle Size Data	Method of Particle Size Sampling[c]
A.5[a]	40% coal; 60% No. 6 oil; 5.7% ash.	54.2% >10 µm 31.3% > 3 µm 12.1% > 1 µm 1.8% > 1 µm	SASS
A.11[b]	50% coal; 22% No. 6 oil; 8% No. 2 oil; 20% H_2O; 4.7% ash.	46% >10 µm 39% > 3 µm 9.4% > 1 µm 5.1% < 1 µm	SASS

[A] Reference 4.

[b] Reference 6.

[c] SASS = Source assessment sampling system. Percent values given for cutoff cyclones; i.e. @ Site A.5, 31% were between 10 and 3 µm, while @ Site A.11, 39% were between 10 and 3 µm.

emitted as SO_2. [COM's made with coal that has highly alkaline ash may emit slightly less than 95 percent of the fuel sulfur since the alkaline ash serves to retain some of the fuel sulfur.]

For a given COM the SO_2 emissions, based on 100 percent of the fuel sulfur emitted as SO_2, can be easily calculated with the following equation:*

$$SO_2 = \left(\frac{x \text{ lb S}}{100 \text{ lb COM}}\right)\left(\frac{1 \text{ lb-mole S}}{32 \text{ lb S}}\right)\left(\frac{1 \text{ lb-mole } SO_2}{1 \text{ lb-moles S}}\right)\left(\frac{64 \text{ lb } SO_2}{\text{lb-mole } SO_2}\right)\left(\frac{\text{lb COM}}{y \text{ Btu}}\right)$$

$$SO_2 = 0.02\ x/y \qquad (3\text{-}1)$$

where: SO_2 = lb SO_2/Btu [x 10^6 = lb $SO_2/10^6$ Btu]

x = Sulfur in COM, %

y = COM heating value, Btu/lb

Depending on the relative sulfur contents of the oil and coal, and the percentage of each fuel in the COM, SO_2 emissions from the COM may be greater or less than SO_2 emissions from the respective oil.

3.3 NITROGEN OXIDE (NO_x) EMISSIONS

Emissions of NO_x from boilers firing COM are relatively more difficult to quantify for all potential applications than are SO_2 and PM emissions. For any particular boiler, NO_x emissions can vary substantially, not only with COM fuel composition, but also with the amount of combustion air (excess air) and, in some cases, with boiler load. Properties of the COM fuel that influence NO_x emissions are: nitrogen content of the fuels used to make the COM, percent coal in the COM, and, possibly, the presence of water in the COM. For a given fuel composition, NO_x emissions can vary significantly from boiler to boiler due to differences in burner and furnace design and the use of combustion air preheat.

The following discussion focuses on NO_x emission data from several different COM combustion tests. These data indicate several general trends, including:

- An increase in NO_x emissions at increased excess air levels.
- An increase in NO_x emissions with increased COM nitrogen content.
- Higher NO_x emissions from COM combustion than from combustion of corresponding oil.

---

*To convert lb/10^6 Btu to Ng/J, multiply by 430.

- NO_x emissions ranging between about 172 ng/J (0.4 lb/10^6 Btu) and 301 ng/J (0.7 lb/10^6 Btu) in most tests, although some tests showed emissions of 430 ng/J (1.0 lb/10^6 Btu) or greater.

However, the data base on NO_x emissions from COM combustion is limited in several respects. First, much of the data have been collected on either laboratory scale furnaces or on relatively small boilers [less than 8.8 MW (30 x 10^6 Btu/hr)]. Only limited NO_x data are available for larger industrial boiler or utility units, and the usefulness of these data is limited by the fact that they were obtained under several different sets of operating and design conditions. Thus, it is difficult to attribute variations in NO_x emissions to changes in a particular operating or design parameter. Secondly, little well-characterized continuous NO_x monitoring data are available for COM combustion. Continuous emission data and the associated boiler and fuel operating data would facilitate efforts to correlate NO_x emissions with such variables as excess air level, boiler load, and fuel nitrogen. Finally, much of the reported NO_x data lack corresponding important boiler operating information such as flue gas oxygen content, basis upon which ppm NO_x is calculated and reported, boiler load, use of air preheat, or fuel nitrogen content. In addition, many of the literature sources from which the data were taken do not specify the methods used to measure NO_x.

Despite these difficulties, the available NO_x data are useful in illustrating the general trends described above.

3.3.1 Effect of Excess Combustion Air Level

The NO_x emission data shown in Figures 3.3-1 and 3.3-2 illustrate that NO_x emissions from COM combustion tend to increase as the excess air level is increased. Figure 3.3-1 shows NO_x data for an 18.5 MW (63 x 10^6 Btu/hr) boiler firing a COM of 50 percent coal, 40 percent No. 6 oil, and 10 percent water. Emissions of NO_x increased from 211 ng/J (0.49 lb/10^6 Btu) at 6.3 percent O_2 to 288 ng/J (0.67 lb/10^6 Btu) at 9.4 percent O_2. (The line through the points in Figure 3.3-1 is a simple least squares curve fit and cannot be applied to predict COM emissions from other boilers.)

Figure 3.3-2 also shows the effect of excess air levels on COM NO_x emissions. The data in this figure, which was obtained on a small [0.5 MW (1.8 x 10^6 Btu/hr)] laboratory furnace, show NO_x emissions to generally be greater at 40 percent excess air than at 20 percent excess air.

3.3.2 Effect of Fuel Nitrogen and COM Composition

Figure 3.3-2 shows that NO_x emissions increase as the percent coal in the COM increases. Larger percentages of coal, which generally has a higher nitrogen content than the oil, lead to increased fuel NO_x formation. (It is interesting to note in Figure 3.3-2 that NO_x emissions from the 30 percent COM at 40 percent excess air are only slightly higher than those from the

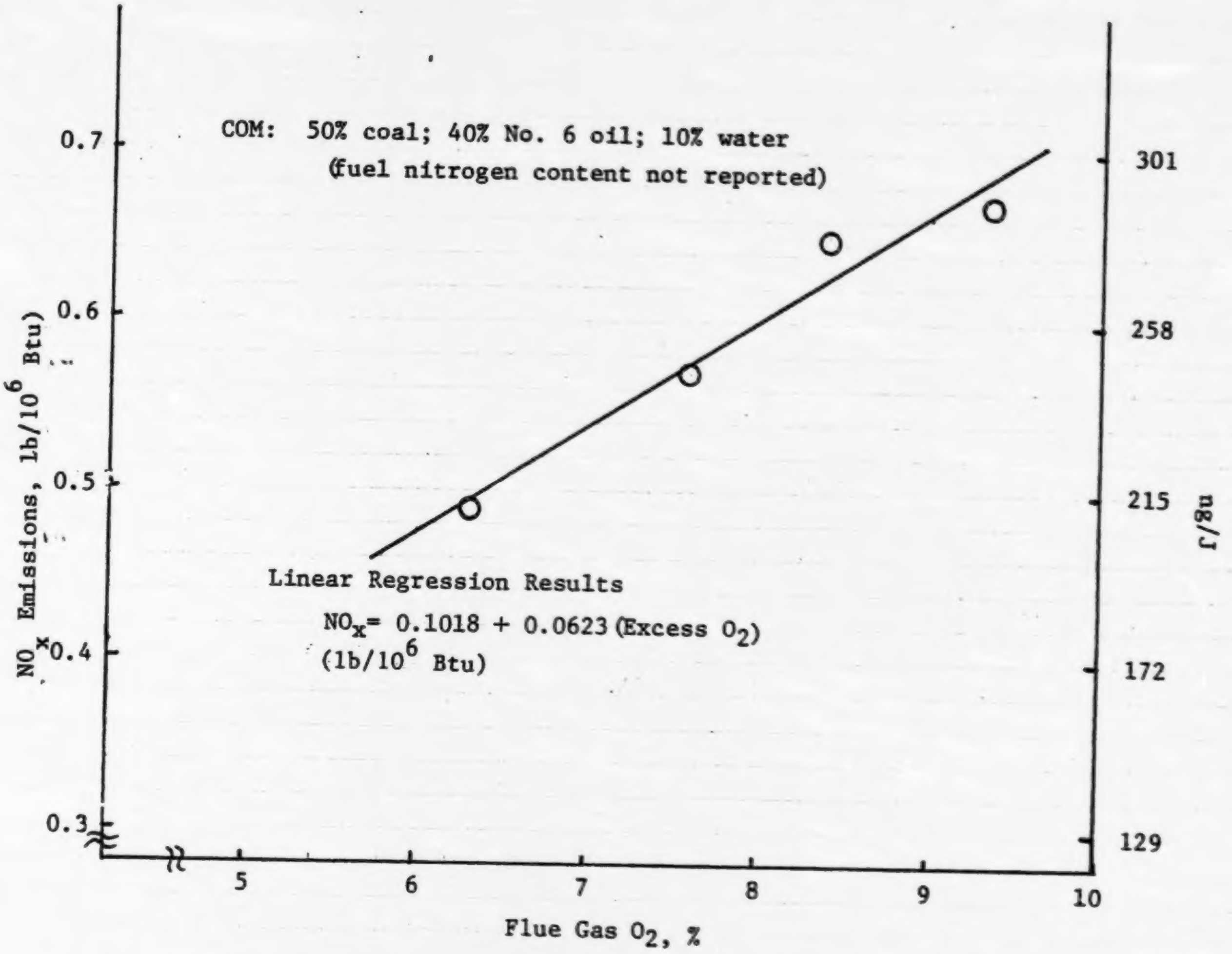


Figure 3.3-1. NO_x emissions from combustion of COM (10% H_2O) in a 63×10^6 Btu/hr boiler - Site A.20. (Reference 8).

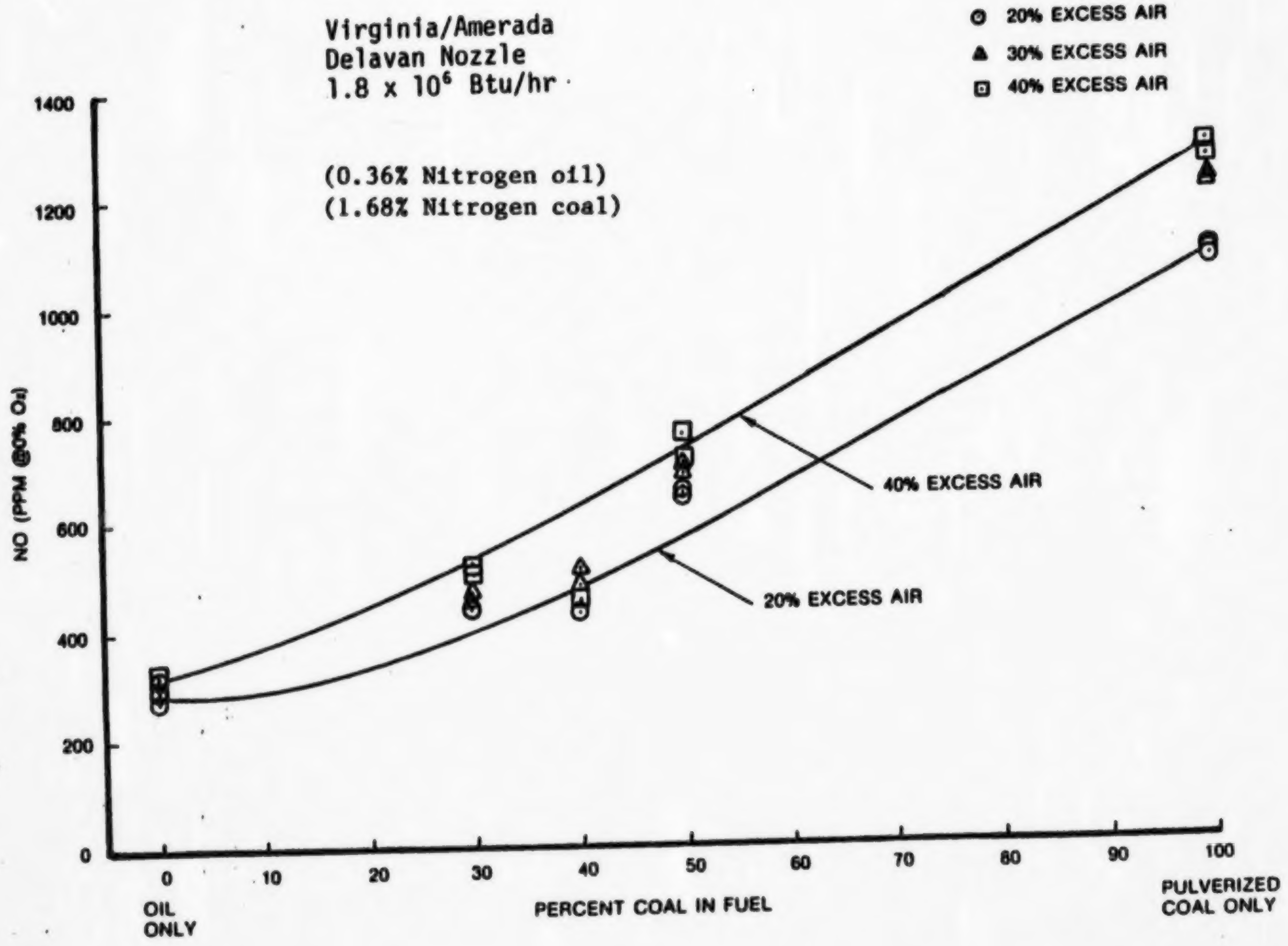


Figure 3.3-2. NO_x emissions from COM combustion in laboratory-scale furnace (1.8 x 10^6 Btu/hr). (Reference 13).

40 percent COM at 20 percent excess air. The use of reduced excess air as a NO_x control method is discussed in Section 3.6).

The effect of fuel nitrogen content is also illustrated in Figures 3.3-3 and 3.3-4a and b. The data in Figure 3.3-3, which were collected in the 0.5 MW laboratory furnace (1.8×10^6 Btu/hr) at an excess air level of 20 percent, show that NO_x emissions generally increased as the amount of nitrogen in the COM increased. [Again, the lines (and equations) shown in Figure 3.3-3 are only for those data and cannot be used to predict NO_x emissions from other COM units.] The conversion of fuel nitrogen to NO_x averaged 30 to 35 percent during the various COM combustion tests.

Figures 3.3-4a and 3.3-4b, which show data from an 8.2 MW (28×10^6 Btu/hr) watertube boiler, also indicate that NO_x emissions tend to be higher with combustion of higher nitrogen COMs. In Figure 3.3-4a, the COM with the highest nitrogen content (0.9 to 1.0 percent) exhibited the highest NO_x levels. Figure 3.3-4a also provides a comparison between "oil-only" NO_x levels and those from COM made with the oil; NO_x emissions from the COM are substantially higher due to the fuel nitrogen contribution of the coal.

The same trend of increasing NO_x with increasing fuel nitrogen is shown in Figure 3.3-4b, with the exception of one data point.

3.3.3 Effect of Burner Design

Burner design, and the resulting flame shape and temperature, can have a significant impact on NO_x emissions. Figure 3.3-5 shows COM NO_x emissions from two different diffuser designs. A 20 percent coal COM was fired in both the "D-2" diffuser and the "D-3" diffuser. The "D-3" diffuser was designed to produce a longer, more diffuse flame. Comparison of the NO_x emissions shows emissions from the "D-3" diffuser (squares in Figures 3.3.5) to be generally lower than emissions from the "D-2" diffuser (triangles in Figure 3.3-5). The longer, more diffuse flame produced by the "D-3" design diffuser results in reduced fuel NO_x formation and lower overall NO_x emissions. In fact, one set of data (solid squares) shows the 20 percent COM fired in "D-3" to have lower NO_x emissions than "oil-only" combustion in the "D-2" diffuser, despite the fact that the COM had a substantially higher nitrogen content than the oil. (Figure 3.3-5 also shows the effect of excess air: in all cases but one, NO_x emissions were greater at 5.5 percent excess air than at 3 percent excess air.

The use of modified burner designs to reduce NO_x emissions (i.e. "low-NO_x" burners) is one of the most promising NO_x control techniques and is discussed further in Section 3.6.

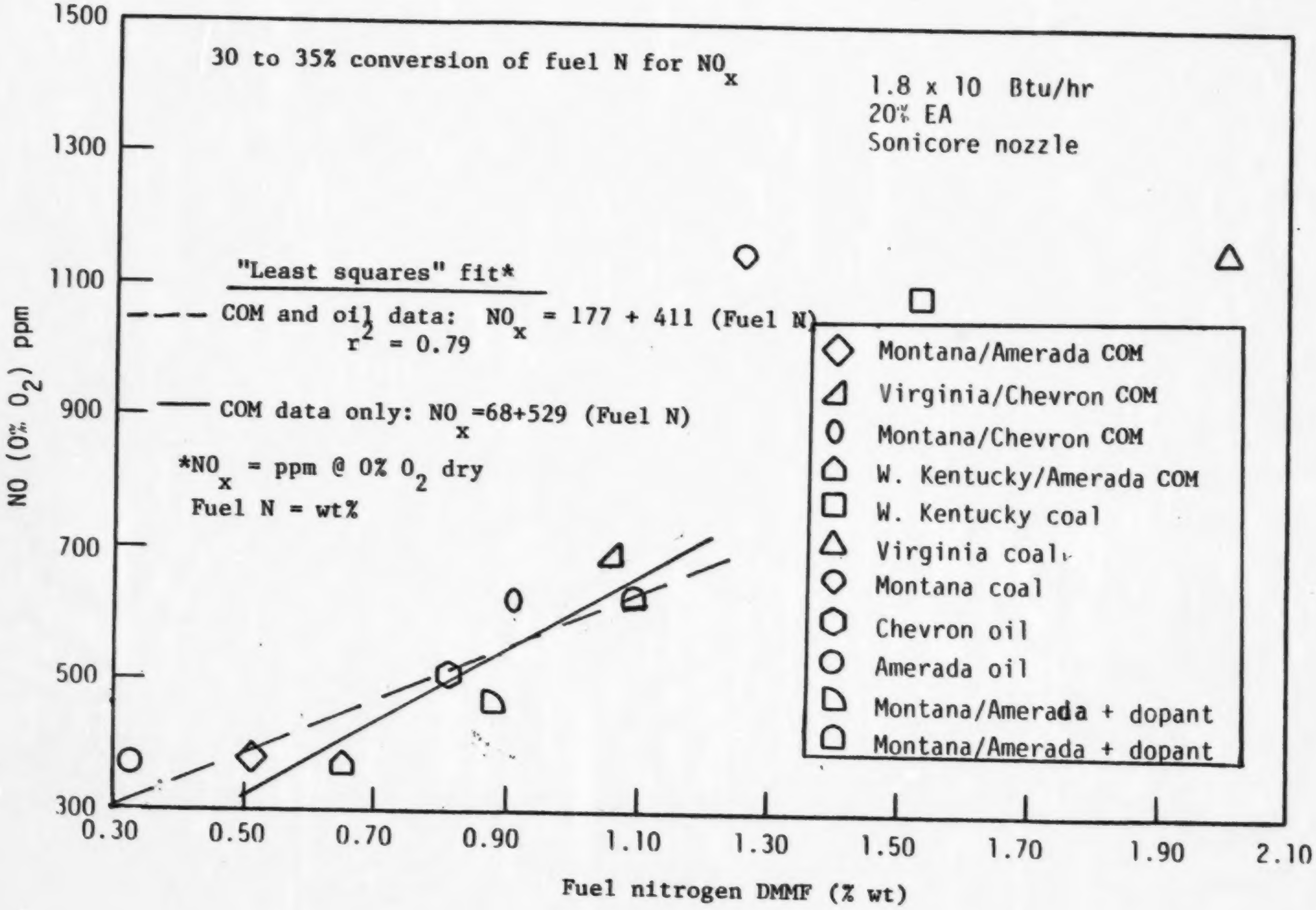


Figure 3.3-3. NO_x emissions from COM and oil combustion in 1.8×10^6 Btu/hr laboratory furnace. (Reference 13).

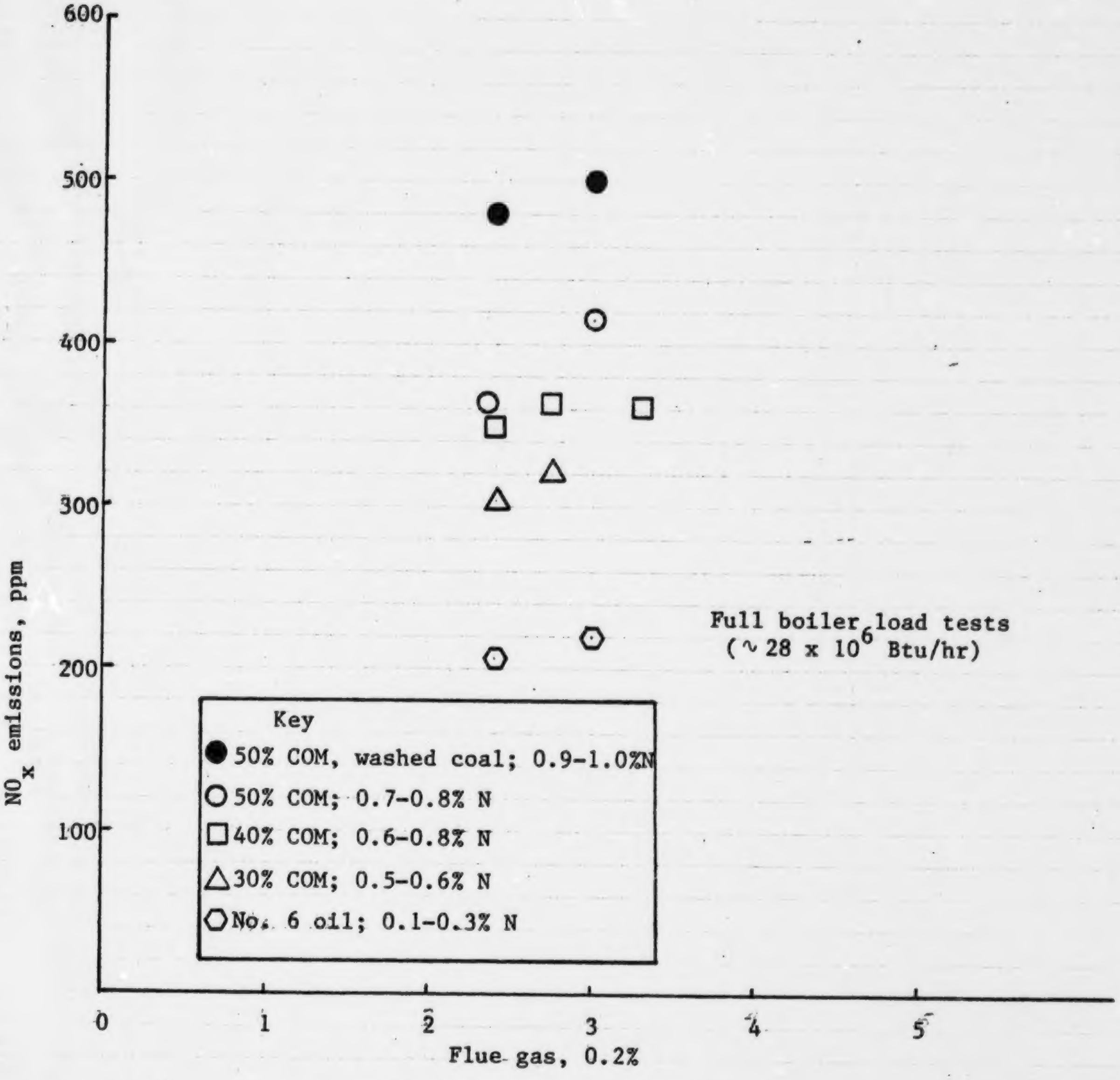


Figure 3.3-4a. NO$_x$ emissions from COM combustion in a 700 hp watertube boiler - Site A.3. (Reference 14).

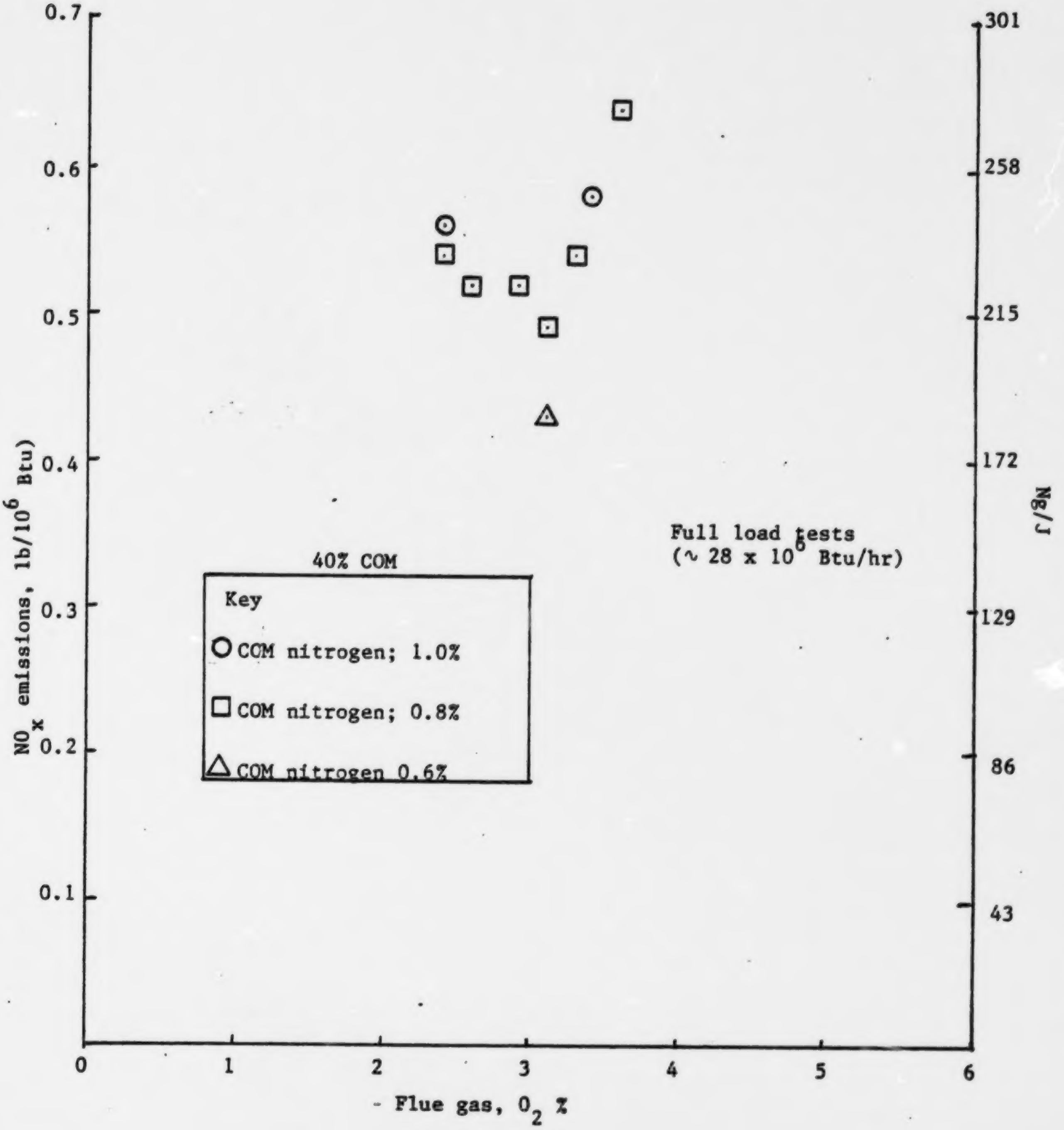
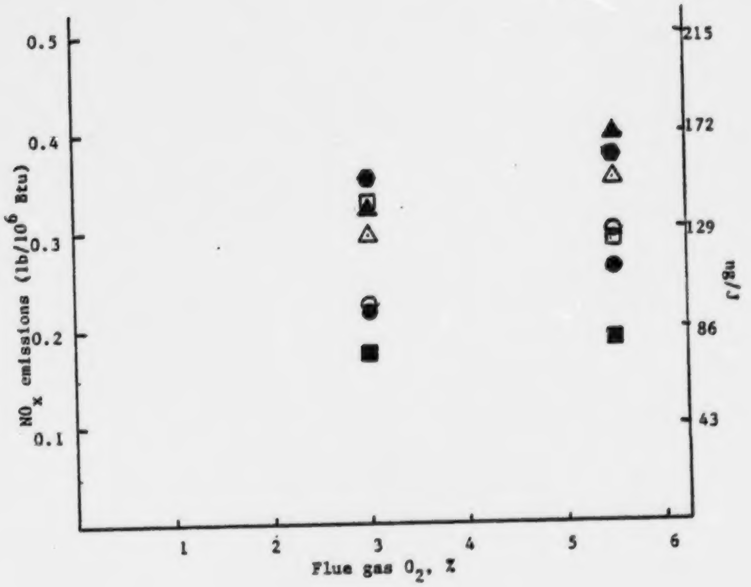


Figure 3.3-4b. NO_x emissions for COM combustion in a 700 hp watertube boiler - Site A.4. (Reference 3).



Key

Firing rate

high ○ } No. 6 oil; 0.23 % nitrogen; D-2 diffuser
low ● }
high □ } 20% COM; 0.4% nitrogen; D-3 diffuser
low ■ }
high △ } 20% COM; 0.4% nitrogen; D-2 diffuser
low ▲ }
high ⬢ 30% COM; 0.6% nitrogen; D.3diffuser

D-3 diffuser produces longer, more diffused flame than 0.2 diffuser, leading to lower NO_x emissions.

Conversion of fuel N to NO_x*

D-2 diffuser:

Fuel	% conversion (Avg.)
No. 6 oil	61.6 to 77.6 (67)
20% COM	41 to 50 (45)

D-3 diffuser:

Fuel	% conversion (Avg.)
20% COM	21.9 to 26.4 (31)
30% COM	29.3 to 38.8 (34)

* Calculated by assuming no atmospheric fixation.

Figure 3.3-5. NO_x emissions from COM combustion in a 100 hp firetube boiler - Site A.2. (Reference 2).

3.3.4 Other NO_x Emission Data

Figure 3.3-6 shows NO_x emission data for COM combustion tests in a 400 MW steam generator. The COM composition varied from 20 to 50 percent coal, and flue gas oxygen varied from 4 percent with oil-firing to up to 26 percent with COM firing. The NO_x emissions were measured under variable conditions, including changes in burner tip design, atomizing steam pressure, and furnace cleanliness. No attempt was made to standardize the NO_x emission results. Thus, it is difficult to discern trends in NO_x emissions from this data set because several of the boiler operating conditions were varied at once. The source from which these data were taken (Reference 9) stated that "future (planned) testing will be more representative of NO_x emissions for COM firing."

Figure 3.3-7 shows NO_x emission data for three units of various sizes. The units fired COM ranging from 20 to 55 percent coal, and some of the COMs contained water.

3.3.5 Summary of NO_x Emission Data

The emission data presented in this section clearly show that NO_x emissions from COM combustion are influenced by the level of excess combustion air, by COM composition (percent coal and fuel nitrogen content) and by burner and furnace design and operating parameters. Emissions of NO_x from COM combustion generally range from about 172 ng/J (0.4 lb/10^6 Btu) to 301 ng/J (0.7 lb/10^6 Btu), depending on the above factors. However, limited data show NO_x emissions up to 430 ng/J (1.0 lb/10^6 Btu) or higher. (Figure 3.3-6).

The limitations of the NO_x data base for COM combustion (discussed at the outset of this section) make it difficult to accurately quantify or predict NO_x emissions for a given application, even if such parameters as excess air level, burner and furnace design, and COM composition are known. Such quantification or prediction will require (1) more detailed knowledge of the mechanisms of NO_x formation in COM combustion and (2) continuous NO_x emission data that will facilitate correlation of NO_x emissions with such variables as excess air and boiler load.

In the first area, formation mechanisms, one source has suggested that the type of oil used to prepare the COM can influence the overall fuel NO_x formation (Reference 13). This same source suggests that other parameters such as sulfur in the fuel and oil atomization characteristics may influence COM NO_x formation.

The ability to predict NO_x emissions for given situations will also facilitate evaluation of alternative NO_x control technologies before they are implemented and possibly promote development of more effective combustion modifications for NO_x control. These capabilities may be especially important in situations where conversion to COM from oil results in increases in NO_x emissions that might trigger PSD review (see Chapter 2).

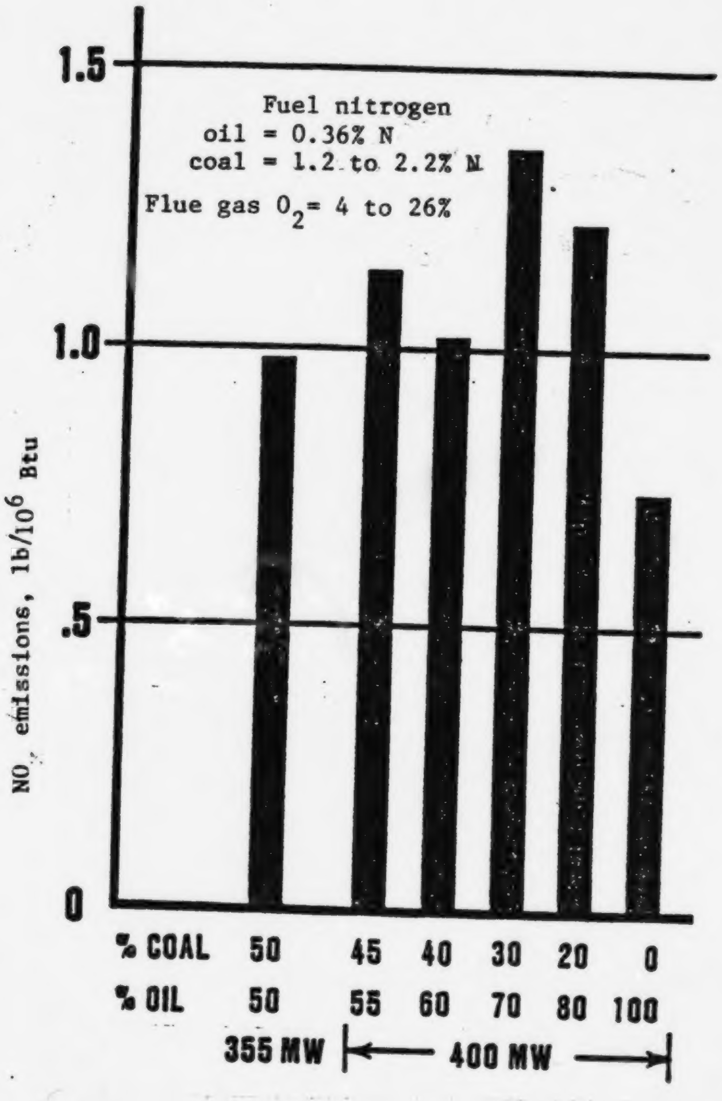
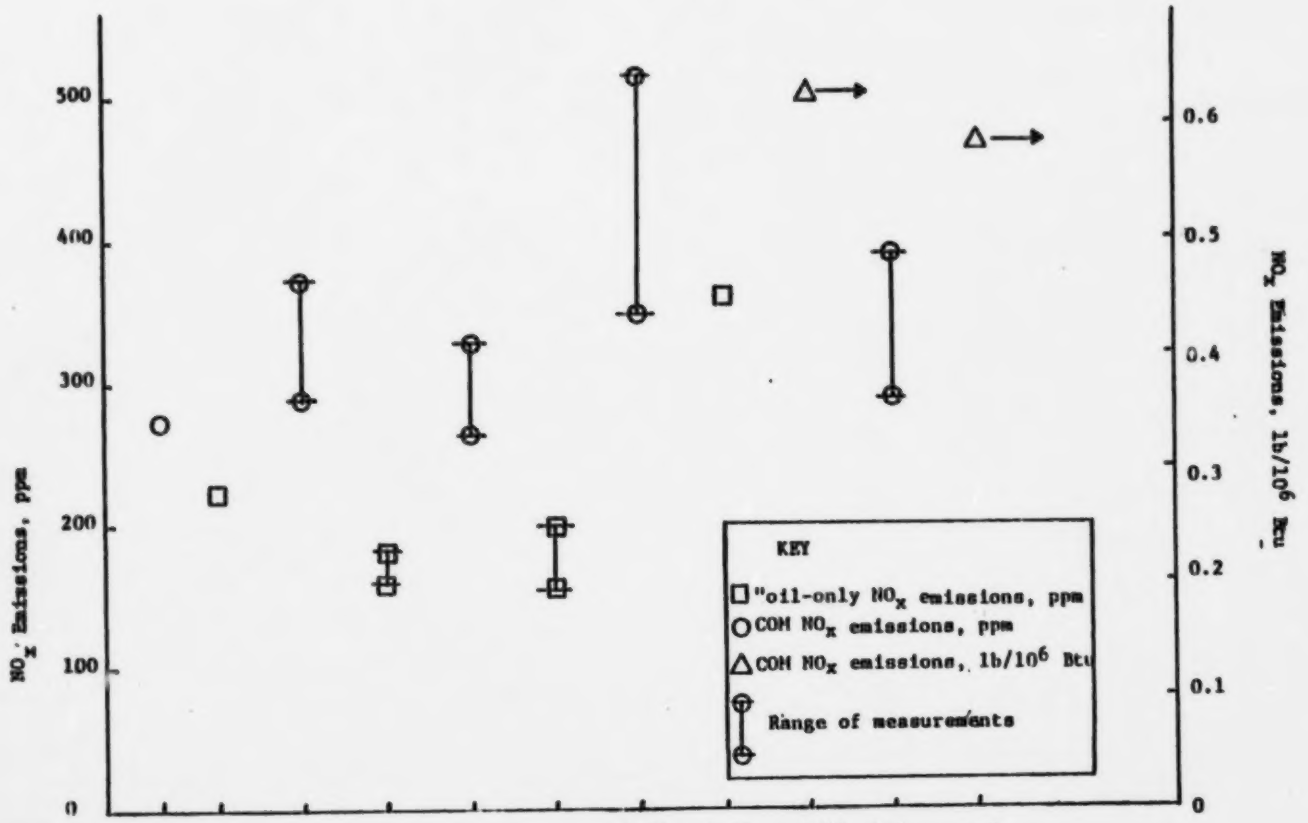


Figure 3.3-6. NO_x emissions from utility boiler firing COM, NO_x measured at air preheater inlet - Site A.14. (Reference 9).

Note: Data taken under a wide variety of boiler operating modes.



SITE	A-1	A-1	A-11	A-11	A-11	A-5	A-5
COM composition							
% coal	20	-	50-55	-	50	40	40
% oil	80	100	30-32	100	30	60	60
% water	-	-	13-20	-	20	-	-
COM nitrogen,%	0.5	0.2	0.4	0.5	0.4	0.9	0.9
O_2,% av	4.3	4.8	5	5.5	6.1	3.0	3.0
range	-	-	-	-	-	2.8-3.7	2.8-3.7
Footnotes	a	a	b	b	b	c	c

Figure 3.3-7. NO_x emissions data from COM combustion.

FOOTNOTES FOR FIGURE 3.3-7.

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[a] No combustion air preheat. Tests conducted in small 100 hp firetube boiler. ($<5 \times 10^6$ Btu/hr). (Reference 15). Corrected to 3% O_2.

[b] NO_x reported (and shown in Figure 3.3-7) as ppm @ 3% O_2 dry; fuel nitrogen content shown based on tests of similar COM at same facility (A.12). 8% No. 2 oil; 22 to 24% No. 6 oil. (Reference 6).

[c] No combustion air preheat. No_x reported and shown in Figure 3.3-7 as ppm @ 3% O_2 dry. (Reference 4).

3.4 TRACE ELEMENT EMISSIONS

Trace elements in the COM fuel exit the boiler either with the bottom ash or with the flue gas, provided there is not significant ash deposition in the boiler. Most of the trace elements emitted with the flue gas are associated with the fly ash, though some may remain in the vapor phase.

Two concepts, labeled partitioning and enrichment, are commonly used to characterize the behavior of trace elements in the combustion process. Partitioning refers to the split of trace elements among the various boiler outlet streams: bottom ash, fly ash, and flue gas. Enrichment, on the other hand, refers to the difference in trace element concentration in the bottom ash and fly ash as a function of particle size.

Based on their partitioning and enrichment behavior, trace elements can generally be divided into four classes:

Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no tendency to be enriched on small particles.

Class 2: Elements which tend to be associated more with the fly ash than the bottom ash or elements which show increasing enrichment with decreasing particle size.

Class 3: Elements which show both Class 1 and Class 2 behavior.

Class 4: Elements which are emitted in the gas phase.

This study is concerned with the emissions of the following trace element emissions from COM combustion: arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), nickel (Ni), selenium (Se), vanadium (V), and mercury (Hg). Table 3.4-1 shows the classification of these elements with respect to the four categories described above.

The amount[16] of trace elements emitted from a particular boiler is dependent on:

- combustion temperature,
- fuel feed mechanism,
- characteristics of the flue gas, and
- COM properties (trace element concentration).

The combustion temperature determines the extent to which specific trace elements are volatized and thus the extent to which they may be emitted with the fly ash or flue gas. The fuel feed mechanism influences

TABLE 3.4-1. CLASSIFICATION OF TRACE ELEMENTS[a]

Trace Element	Classification[b]	Comments
Arsenic (As)	Class 2	-
Beryllium (Be)	Class 3	Has exhibited Class 1 and Class 2 behavior in some studies.
Cadmium (Cd)	Class 2	-
Chromium (Cr)	Class 3	Has shown Class 1 and Class 2 behavior in some studies.
Nickel (Ni)	Class 3	Has shown Class 1 and Class 2 behavior.
Selenium (Se)	Class 2	Some Se also emitted in gas phase (Class 4).
Vanadium (V)	Class 3	Has shown Class 1 and Class 2 behavior.
Mercury (Hg)	Class 4	Hg is Class 4 at normal stack temperatures (300°F+). Lower temperatures will cause condensation of gaseous Hg, and Class 2 behavior will be exhibited.

[a] Reference 17.

[b] See text for explanation of Classes.

the partitioning of non-combustible trace elements between the bottom ash and the fly ash. The temperature of the flue gas affects the relative amounts of volatile trace elements which are emitted condensed on the fly ash particles compared to being emitted as a vapor.

The concentration of trace elements in the coal and oil and the relative amounts of coal and oil used to prepare the COM will determine the concentration of trace elements in the COM. Table 3.4-2 shows average trace element concentrations for three coals and for a typical residual oil. These data show that, on the average, coal has higher concentrations of As, Be, Cr, Hg, and Se. Residual oil has higher concentrations of Cd, Ni, and V.

Table 3.4-3 shows the available trace element data for COM combustion at two sites. Data were available from Site A.5, in which a 40 percent coal COM was fired in a 10,800 kg steam/hr (24,000 lb/hr) watertube boiler and from Site A.11, a 3,015 kg steam/hr (6,700 lb/hr) boiler burning COW with the following composition: 50 percent coal, 22 percent NO. 6 oil, 8 percent No. 2 oil, and 20 percent water.

Site A.11 had higher emissions of As and V than Site A.5, but emissions of other trace elements were about the same at the two sites. No trace elements were found to be emitted in quantities exceeding 1.5 ng/J (0.003 lb/10^6 Btu). No COM fuel trace element analyses were presented with the emission data.

Both references from which the trace element data were obtained note that potential contamination from the SASS train and sample preparation could introduce contamination for a number of trace elements, including nickel and chromium.

3.5 POLYNUCLEAR ORGANIC MATERIAL (POM)

Polynuclear organic material (POM) emissions from COM combustion have been determined in only a limited number of studies.[4,6,23] In general, the POM emissions data obtained from these studies is highly variable and prediction of potential POM emissions from other sites is not possible.

The amount of POMs emitted from any combustion source is dependent on the formation and the transformation mechanisms of the POM. POMs are formed in the combustion zone either by the breakdown of larger molecules or by the building up of smaller ones. Evidence is available[18] to indicate that POMs form in the vapor phase and later condense on flue gas particulate matter. POM formation is related to combustion efficiency and POM transformations are related to boiler and downstream flue gas temperatures. When properly fired, oil-only combustion has been shown to contribute almost no POM emissions to the environment while coal-only combustion produces POM emissions in unpredictable patterns.[18] Therefore, the POM emissions from COMs cannot be related to the fuel content of any particular component.

TABLE 3.4-2. AVERAGE TRACE ELEMENT CONCENTRATIONS IN COAL AND RESIDUAL OIL (ppm)[a]

Trace Element	Eastern Bituminous	Western Bituminous	Bituminous	Residual Oil
Arsenic (As)	11.4	1.94	8.82	0.8
Berylium (Be)	1.00	0.86	0.96	0.08
Cadmium (Cd)	0.42	1.28	0.66	2.27
Chromium (Cr)	31.2	11.8	25.9	1.3
Mercury (Hg)	0.21	0.099	0.18	0.04
Nickel (Ni)	19.1	14.8	17.9	42.2
Selenium (Se)	3.01	1.54	2.60	0.7
Vanadium (V)	37.2	23.7	33.5	160

[a] Reference 18.

TABLE 3.4-3. TRACE ELEMENT EMISSION DATA FOR COM COMBUSTION[a]

	Trace Element Emissions lb/10^6 Btu (ng/J)	
Trace Elements	Site A.5[b] (40% COM)	Site A.11[c] (50% COW)
As	2.4×10^{-4}(0.102)	2.79×10^{-3}(1.2)
Be	1.08×10^{-5}(0.00464)	1.0×10^{-5}(0.0046)
Cd	1.33×10^{-6}(5.73×10^{-4})	2.56×10^{-6}(0.0011)
Cr	1.39×10^{-3}(0.599)	1.1×10^{-3}(0.480)
Ni	9.74×10^{-4}(0.419)	6.05×10^{-4}(0.260)
Se	1.49×10^{-5}(0.0064)	6.28×10^{-5}(0.027)
V	1.08×10^{-3}(0.464)	3.02×10^{-3}(1.3)
Hg	5×10^{-7}(2.15×10^{-4})	9.30×10^{-6}(0.004)

[a] All data taken with source assessment sampling system (SASS).

[b] Reference 4.

[c] Reference 6.

Table 3.5-1 shows the available POM data for COM combustion at two sites. These data were taken from a 4104 kg steam/hr (9000 lb/hr) firetube boiler and a 5400 kg steam/hr (12,000 lbs/hr) firetube boiler.[6,23] A third study attempted to measure POM emissions from a 10,800 kg steam/hr (24,000 lb/hr) watertube boiler, however, no POM emissions were detected[4] from this source.

At Site A.9 POM emissions were measured from combustion of COM alone and with limestone additive for SO_2 emission control. As seen in Table 3.5-1, the tests run with COM and limestone have consistently higher POM emissions than COM alone. No explanation for this behavior was given. Site A.12 reported POM emissions from the combustion of COM alone and with COM mixed with soda ash for SO_2 emissions control. Table 3.5-1 indicates that fewer POM compounds were found and their concentrations did not change as drastically when soda ash was added to the COM.

At Site A.12, the addition of limestone to the COM did not result in a decrease in SO_2 emissions but actually increased these emissions. At site A.9, the addition of soda ash to the COM decreased SO_2 emissions by 95 percent. These additives could have some potential effect on long-term SO_2 emissions from COM fired sources, but the data is too limited to definitively predict the best additive to use.

3.6 APPLICABLE CONTROL TECHNOLOGIES

This section discusses the technologies applicable to COM-fired boilers for control of PM, SO_2, NO_x, and trace element air emissions. As stated in the introduction to this chapter, the applicable technologies are basically those that are currently in use on existing oil- and coal-fired boilers. In addition, a few newer emission control technologies being developed are likely to be applicable to COM-fired units. These newer techniques, such as dry injection of sodium-based compounds in the flue gas to reduce SO_2 emissions, are still in the pilot-scale or demonstration stage. But with continued research and development these technologies may become viable for commercial application.

The following sections discuss the candidate control technologies for COM-fired boilers. Techniques for controlling PM are presented in Section 3.6.1 and techniques for controlling both SO_2 and PM are highlighted in Section 3.6.2. Section 3.6.3 focuses on NO_x control and Section 3.6.4 deals with trace element emission control. Table 3.6-1 summarizes all the applicable technologies. Each of the candidate technologies are discussed with respect to the following general criteria:

- status of development,
- use on existing oil- and coal-fired boilers,
- applicability to COM-fired units,

TABLE 3.5-1. POM EMISSIONS FROM COM COMBUSTION

Compound	Site A-9[6] COM	 COM + Limestone	Site A-12[23] COM	 COM + Soda Ash
Acenaphthene	0.8	3.0	a	a
Acenapthylene	a	2.0	a	a
Anthracene	0.2	1.0	a	a
Chrysene	0.2	0.6	a	a
2,4 xylenal	a	4.0	a	a
Fluoronthene	0.3	0.6	0.05	a
Fluorene	2.0	7.0	a	a
Naphtlalene	41	110	a	a
Phenanthrene	4.9	17	0.1	0.7
Benz(a)anthracene	0.1	a	a	a
Phenol	2.8	12	a	a
Pyrene	0.2	0.6	a	a
Other polynucleus	0.6	0.6	0.2	1.0

[a] Below detection limits.

TABLE 3.6-1. CANDIDATE CONTROL TECHNOLOGIES APPLICABLE TO COM-FIRED BOILERS

Pollutant	Candidate Control Technology	Literature Sources[a]
Particulate Matter	Fabric filter, ESP, Wet Scrubber, Mechanical Collector, Side Stream Separator.	1. Roeck, D. R. and R. Dennis (GCA Corporation). Technology Assessment Report for Industrial Boiler Applications: Particulate Collection. EPA-600/7-79-178h. U. S. Environmental Protection Agency. Research Triangle Park, NC. December 1979.
		2. Environmental Protection Agency. Fossil Fuel Fired Industrial Boilers - Background Information for Proposed Standards. Preliminary Draft. Research Triangle Park, NC. June 1980. Section 4.1.
SO_2 and SO_2/PM Combined control	Wet FGD ("throwaway" and regenerable processes).	3. Dickerman, J. C. and K. L. Johnson. (Radian Corporation). Technology Assessment Report for Industrial Boilers: Flue Gas Desulfurization. EPA-600/7-79-178i. U. S. Environmental Protection Agency. Research Triangle Park, NC. November 1979.
		4. Reference 2 above; Section 4.2.
	Spray Drying, Dry Injection	5. Kelly, Mary E. and S. A. Shareef (Radian Corporation). Third Survey of Dry SO_2 Control Systems. EPA-600/7-81-097. U. S. Environmental Protection Agency. Research Triangle Park, NC. August 1981.
	• Fuel Cleaning	
	Physical Coal Cleaning	6. Buroff, J. et al. (Versar, Inc.) Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal. EPA-600/7-79-178c. U. S. Environmental Protection Agency. Research Triangle Park, NC. December 1979.

TABLE 3.6-1. (Continued). CANDIDATE CONTROL TECHNOLOGIES APPLICABLE TO COM-FIRED BOILERS

Pollutant	Candidate Control Technology	Literature Sources[a]
SO_2 and SO_2/PM	• Oil Hydrodesulfurization	7. Comely, E. A. et al. (Catalytic, Inc.) Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning. EPA-600/7-79-178b. U. S. Environmental Protection Agency. Research Triangle Park, NC. July 1980.
	Alkaline Fuel Additives	8. Dooher, J. P. "Sulfur Dioxide Removal in the Combustion of Coal/Oil/Water Emulsions." In: Proceedings of the Third International Symposium on Coal-Oil Mixture Combustion. (Sponsored by DOE's Pittsburgh Energy Technology Center; Pittsburgh, PA) April 1981.
		9. DeRosier, R. (Acurex Corporation). Environmental Assessment of a Firetube Boiler Firing Coal/Oil/Water Mixtures. Volume I: Technical Results. EPA Contract No. 68-02-3188. U. S. Environmental Protection Agency. Research Triangle Park, NC. November 1981.
NO_x	Combustion Modifications (LEA, staged combustion, FGR, low-NO_x burners)	10. Lim, K. J., et al. (Acurex Corporation). Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modifications. EPA-600/7-79-178f. U. S. Environmental Protection Agency. Research Triangle Park, NC December 1979.
		11. Reference 2 above; Section 4.3.
	Ammonia Injection	12. Castaldini, C. et al/Acurex Corporation). Technical Assessment of Thermal De NO_x Process. EPA-600/7-79-117. U. S. Environmental Protection Agency. Research Triangle Park, NC. May 1979.

TABLE 3.6-1. (Continued). CANDIDATE CONTROL TECHNOLOGIES APPLICABLE TO COM-FIRED BOILERS

Pollutant	Candidate Control Technology	Literature Sources[a]
NO_x	Flue Gas Treatment	13. Jones, G. D. and K. L. Johnson (Radian Corporation). Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment. EPA-600/7-79-178g. U. S. Environmental Protection Agency. Research Triangle Park, NC. December 1979.

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[a] These literature sources are informative summary reports on the technology design and operation on coal- and oil-fired boilers. The sources also provide many, more detailed, references.

- retrofit suitability, and
- demonstrated emission control capability.

The emission control capability of the technologies is discussed in fairly general terms, with the focus on the capability of the technology to reduce emissions from COM combustion to levels typical of oil-firing. (See Section 2.3 - Regulatory Requirements.)

Also, any multipollutant control capabilities (i.e. the capability to control one or more of the air emissions simultaneously) of the technologies are identified.

Based primarily on these criteria, several control technologies are selected for further evaluation of their environmental and cost impacts on COM-fired boilers. The impacts of the selected technologies are presented in detail in subsequent chapters of this report.

The control technology discussions presented in the chapter are necessarily brief and do not, in general, deal with the design and operational aspects of the technology. However, Table 3.6-1 lists a number of references in which detailed information on the technologies can be found.

3.6.1 Particulate Matter (PM) Control Technologies

The PM control technologies currently used on coal-fired boilers are:

- electrostatic precipitators (ESPs),
- fabric filters,
- venturi scrubbers,
- side stream separators, and
- mechanical collectors.

Side stream separators and mechanical collectors are used only on industrial coal-fired boilers. Most industrial and utility oil-fired boilers are equipped with ESPs or have no particulate matter control device. Precipitators are primarily used on utility boilers, while most oil-fired industrial boilers are uncontrolled. Mechanical collectors and venturi scrubbers are not often used to control PM emissions from oil-firing due to the relatively small size of the oil fly ash (generally less than 2 micrometers) and the inefficiency of these collectors in removing small particles. Fabric filters are not used on oil-fired boilers because the hygroscopic nature of the fly ash can potentially cause severe bag blinding problems.[18]

With the exception of side stream separators, each of these PM control technologies has been applied for a number of years to industrial and/or utility boilers. Side stream separators are basically mechanical collectors modified to have a slipstream of flue gas drawn through a small fabric filter. These devices have recently been installed on several coal-fired spreader stokers in the automobile industry.[12]

Each of these control technologies is applicable to controlling PM emissions from COM-fired boilers. However, fabric filters, ESPs, and venturi scrubbers are likely to be the only technologies capable of reducing PM emissions to the levels typical of uncontrolled emissions from oil combustion [i.e. 43 ng/J (0.1 lb/10^6 Btu) or less]. The large portion of COM fly-ash particles less than 10 or 15 micrometers (Section 3.1.2) will not be efficiently collected by mechanical collectors. And, although side stream separators have been shown to be more efficient with respect to the smaller fly ash particles, there are no data to indicate that emissions could be reduced to the 43 ng/J (0.1 lb/10^6 Btu) level.[12]

The retrofit suitability of these PM control technologies to existing boilers without PM controls will depend on site-specific factors. Foremost among those site-specific factors is space availability. Mechanical collectors and side stream separators have the lowest space requirements; fabric filters and ESPs will require more area. Although the venturi scrubber itself may have lower space requirements than ESPs or fabric filters, the sludge handling equipment could make the overall space requirements for a scrubber greater than for the other control technologies.

3.6.2 Combined SO_2/PM Control Technologies

The combined SO_2/PM control technologies currently in use are:

- wet flue gas desulfurization (FGD),
- spray drying FGD, and
- fuel cleaning and blending prior to combustion.

Technologies still in the developmental stage include:

- dry injection of sodium-based compounds and
- alkaline fuel additives.

With the exception of the alkaline fuel additive technique, all of these technologies can be used to simultaneously control SO_2 and PM.

3.6.2.1 Wet FGD Systems

Although there are several types of wet FGD processes, the systems most commonly applied to coal- and oil-fired boilers are:

- sodium throwaway
- lime/limestone, and
- double alkali.

In industrial boiler applications, sodium throwaway systems accounted for 83 percent of the wet FGD systems operating, planned, or under construction as of 1979.[19] Double alkali systems account for 12 percent and lime and limestone, spray drying, and ammonia-based processes make up the remaining 5 percent. These figures are somewhat misleading, however, since 70 percent of the existing, under construction, and planned industrial boiler FGD systems are or will be applied to small oil-field steam generators. Double alkali systems have been applied only to coal-fired industrial boilers.

Recent data for utility FGD systems indicates no existing oil-fired boilers with FGD systems.[20] Lime and limestone processes are the most common wet FGD systems for existing coal-fired utility boilers, followed by double alkali, spray drying and once-through sodium processes.

These data indicate that there are few existing oil-fired boilers with FGD systems, but that sodium throwaway, double alkali, and lime/limestone are the most common wet FGD processes. These processes are relatively less complicated than regenerable wet FGD systems and have lower space requirements. Although the sodium throwaway process is the least chemically complex process, disposal of the liquid waste from this process may in some instances require expensive wastewater treatment. Double alkali and lime/limestone systems produce a wet sludge which is generally disposed of in on- or off-site ponds or landfills. Wet FGD systems with proper scrubber designs (usually venturi- or tray-type) can remove fly ash as well as achieve 90+ percent SO_2 removal. (In some cases, it may be desirable to put a mechanical collector ahead of the scrubber. The mechanical collector will capture the larger fly ash particles and help reduce the potential scrubber errosion and plugging.)

3.6.2.2 Dry FGD Systems

Spray drying (lime reagent) and dry injection of sodium-based alkalis are two dry FGD processes that may be applicable to COM-fired boilers. Of the two, spray drying is the only one to have been commerically applied, and its use is relatively recent. A total of 11 utility and at least 6 industrial spray drying systems are or will be applied to coal-fired boilers.[21] Currently, only two industrial systems are in commercial operation. However, numerous small- and large-scale demonstrations of the process have been conducted.[22]

Dry injection has only been investigated at the pilot-scale, and no commercial applications are currently planned.[22] However, the demonstration test results have indicated that substantial SO_2 removal can be achieved with this process.

Both spray drying and dry injection have been demonstrated to achieve up to 90 percent SO_2 removal at inlet SO_2 concentrations of less than 2,000 ppm.[22] High SO_2 removal at inlet SO_2 concentrations greater than about 3,000 ppm have not been demonstrated in commercial or demonstration program results reported to date.

Spray drying and dry injection include fabric filters as part of the system. The fabric filter serves to collect fly ash as well as the dry waste solids formed during desulfurization.

Dry injection requires space for the fabric filter and reagent handling and injection equipment. The spray dryer, fabric filter, and reagent handling and preparation equipment constitute the space requirements for the spray drying process. Neither system requires wet sludge handling equipment.

3.6.2.3 Fuel Cleaning and Blending

Fuel cleaning, in the form of physical coal cleaning and oil hydrodesulfurization, reduces both the ash and sulfur content of the fuel prior to combustion resulting in lower PM and SO_2 emissions. The degree of sulfur and ash reduction achievable with fuel cleaning depends on the properties of the uncleaned fuel and the type of fuel cleaning process used. Physical coal cleaning and oil hydrodesulfurization are both well-established technologies. Fuel blending involves preparing the COM from cleaned or naturally occuring low sulfur coals and oils. Fuel blending for COM preparation will be influenced by the coal and oil properties and the desired properties of the COM.

Fuel cleaning and fuel blending have a distinct advantage over FGD systems for retrofit situations in that there are no boiler-site equipment or space requirements. However, particulate matter control equipment is still likely to be required for most conversions.

3.6.2.4 Alkaline Fuel Additives

Limited tests have been conducted using soda ash or calcium-based alkalis. The dry alkaline material is added to the COM fuel prior to combustion to reduce SO_2 emissions. The most recent of these tests (Reference 37, Site A.9) showed a 95 percent reduction in SO_2 emissions when soda ash was added to a COW fuel (10 percent water). However, there was significant ash disposition and boiler fouling during these tests, forcing the test burn to be cut back from 6 to 3 hours.[22]

As expected, ash emissions were significantly greater for the test with soda ash additive relative to combustion of the COM alone. Also, CO emissions were substantially higher during the soda ash additive test due to reduced combustion efficiency.

Other tests of alkaline fuel additives (Sites A.7 and A.8) showed the alkali to have significant effects on the rheology of the COW, causing the mixture to separate under shear stress. These effects can lead to clogging in pumps, pipes, and burner nozzles.

No long-term tests of this technique have been conducted to date.

The use of alkaline fuel additives requires fuel preparation and reagent handling equipment. In addition, a PM control device will also be required to capture fly ash and other PM emissions.

3.6.3 NO_x Control Technologies

Control technologies for NO_x can be divided into two groups: (1) combustion modification controls and (2) post-combustion controls.

Combustion modification techniques include:

- low excess air operation (LEA),
- staged combustion,
- flue gas recirculation (FGR), and
- low-NO_x burners.

Post-combustion controls include ammonia injection ("thermal De-NO_x") and flue gas treatment techniques.

3.6.3.1 Low excess air (LEA)

Low excess air operation involves reducing the amount of excess combustion air supplied to the boiler. This technique can generally be easily implemented on existing units. In addition to moderately reducing NO_x emissions LEA can improve boiler efficiency and reduce fuel costs.

Equipment requirements for LEA operation include flue gas O_2 and CO_2 monitor systems and low air flow alarms. Compartmental windboxes may be required for multiburner units to assure proper air flow distribution.[24] Air flow levels must be maintained above minimum levels to avoid increases in smoke, CO, or unburned hydrocarbon emissions.

3.6.3.2 Staged Combustion

Staged combustion involves injecting a portion of the combustion air through ports located downstream of the burner(s). This practice reduces the air to fuel stoichiometry at the burner, and is effective in controlling formation of fuel NO_x. Because it is more effective in reducing fuel NO_x, staged combustion achieves greater overall NO_x reductions than LEA. Staged combustion has been demonstrated and used commercially on large field-erected pulverized coal-, oil-, and gas- fired industrial boilers. In

California, staged combustion is used on some residual oil- and gas-fired utility boilers larger than 73 MW (250 x 10^6 Btu/hr) to help meet state and local NO_x regulations for existing boilers.[24]

The effectiveness of staged combustion depends strongly on proper location of the secondary air ports.[24] The optimum location may vary with boiler type and size. Retrofit of staged combustion air ports may not be feasible on some boilers, especially package units.

An alternative to modifying the boiler to accommodate secondary air injection ports is called "burners out of service" (BOOS). With this technique the secondary is injected through downstream burners that have been taken out of service (i.e. no fuel is supplied to these burners). Proper implementation of BOOS requires careful selection of the in-service burner pattern and close control of the air flow.[25] Also, BOOS will require derating of the boiler unless the fuel delivery system is modified.[25]

As with LEA, flue gas O_2 and CO_2 monitors and automatic air control systems are recommended for staged combustion.

3.6.3.3 Flue Gas Recirculation (FGR)

The flue gas recirculation technique is based on returning a portion of the flue gas to the furnace through the burner windbox. The recirculated flue gas has a low O_2 level and absorbs some of the heat released during combustion, thus lowering the excess air and bulk furnace gas temperature and resulting in reduced thermal NO_x formation. FGR, which does not reduce fuel NO_x, will not be as effective in reducing NO_x from COM combustion as it is in reducing NO_x from gas- and distillate-oil firing. This is due to the contribution of fuel nitrogen (fuel NO_x) to total NO_x emissions from COM.

FGR is commercially available and applicable to gas- and distillate oil-fired industrial boilers. In 1978, FGR was installed on two new 15 MW (50 x 10^6 Btu/hr) package gas/oil-fired boilers in Southern California.[26] However, FGR is used on few, if any, existing residual oil-fired boilers.

Implementation of FGR requires extra fan capacity and ducting. Also, burners and windboxes must be modified for the increased gas flow. FGR will be relatively more difficult and costly to retrofit to most existing oil-fired boilers than LEA or staged combustion.

Proper air flow and recirculation gas flow control must be incorporated to maintain good combustion and flame stability.

3.6.3.4 Low-NO_x Burners

New burner designs, labeled low-NO_x burners, are being developed for controlled mixing of air, fuel, and combustion products within the flame zone to reduce NO_x formation. Low-NO_x burners that are being developed for oil-firing generally use a combination of cooling and staging.[26] Flame surface area is increased for greater heat dissipation; burner-area gas recirculation is used to cause rapid quenching of the flame and cool the combustion process; and controlled air/fuel mixing is used to provide a staged combustion effect. Thus, the low-NO_x burner should be effective in reducing both thermal and fuel NO_x, and can usually achieve greater NO_x reductions than LEA, staged combustion, or FGR.

Low-NO_x burners are required as "best available control technology" for new residual oil-fired boilers in at least two states (California and Texas). However, their use on existing oil-fired boilers is not widespread since low-NO_x burners are a relatively new technology, having only recently been applied to commercially operating boilers.[26]

Retrofit of low-NO_x burners to existing boilers should be feasible in many cases. However, care must be exercised in selecting the proper low-NO_x burner design for an existing boiler. For example, some LNB designs under development may result in an extended flame zone, leading to flame impingement on the back wall of the boiler if the firebox is not large enough.[26]

3.6.3.5 Ammonia Injection

Ammonia injection involves the non-catalytic reduction of NO_x in the flue gas to nitrogen and water. Ammonia is used as the reducing agent. The technique is often referred to as selective non-catalytic reduction or thermal De-NO_x. The effectiveness of the technique is highly dependent on the temperature at the point where the ammonia is injected into the boiler. Specifically, up to 40 percent NO_x reduction can occur if the temperature is between 1200 and 1260K (1700° to 1800°F); outside the range of 1175 to 1350K (1650° to 2000°F), however, less than 10 percent of the NO_x can be reduced to nitrogen and water.[26]

Ammonia injection techniques are commercially offered in the United States and Japan. It is currently being applied to one domestic operating industrial boiler in California. Ammonia injection is scheduled for application on large residual oil-fired utility boilers in Southern California by 1982.[26]

The required reaction temperatures for noncatalytic NO_x reduction are found in different areas of the boiler depending on boiler design and operating load. For example, the desired temperatures may be found in the convective section of the boiler at full load. But changing boiler load causes a shift in temperature profile through the boiler, and optimum temperatures may occur at another location. Injection of hydrogen effectively widens the useful temperature range. But to avoid curtailment of boiler load-following capability it may be necessary to install multiple injection grids. This technique, however, has not been demonstrated,[26] and may be infeasible to retrofit to existing boilers.

Sulfur containing fuels also present a potential problem for ammonia injection. The formation of ammonium sulfate or ammonium bisulfate can cause plugging of an air preheater or corrosion of boiler parts. Additionally, to see that ammonia emissions to the atmosphere are minimized, ammonia sensors and feedback control systems for the injectors will be required.[26]

3.6.3.6 Flue Gas Treatment (FGT)

Post-combustion flue gas treatment techniques for control of NO_x emissions use either a gas phase reaction or liquid absorption to reduce NO_x. The primary NO_x FGT processes are:

- selective catalytic reduction (SCR),
- wet scrubbing (for NO_x and SO_2), and
- electron beam irradiation.

None of these processes has been applied to commercially operating industrial or utility boilers in the U. S. The earliest domestic commercial applications of SCR are planned for 1982 on two low sulfur oil-fired boilers in Southern California. Development of wet scrubbing processes for combined SO_2/NO_x removal has not progressed beyond the pilot-scale stage and the electron beam irradiation process is also in the pilot- scale stage.[26]

3.6.4 Trace Element Control

Trace elements can be controlled by the same technologies used to control particulate matter. As discussed earlier, the PM control technologies most suitable for COM-fired boilers are fabric filters, ESPs and wet scrubbers. These techniques are effective in controlling the small fly ash particles that contain most of the trace elements emitted in the flue gas. Wet scrubbers are effective in controlling emissions of trace elements that remain in the vapor phase (primarily Hg and Se).

3.7 SELECTION OF CONTROL TECHNOLOGIES FOR FURTHER EVALUATION

Table 3.7-1 shows the control technologies applicable to COM-fired boilers that have been selected for further evaluation of their environmental and cost impacts.

These technologies were selected primarily on the basis of their effectiveness in controlling PM, SO_2, or NO_x emissions, status of development, retrofit suitability, and multipollutant control capability.

The following technologies were not selected for further evaluation:

- sidestream separators and mechanical collectors (PM),

TABLE 3.7-1. CONTROL TECHNOLOGIES SELECTED FOR FURTHER EVALUATION

Pollutant	Control Technologies to be Evaluated[a]
PM	Fabric filter ESP Wet scrubber
SO_2/PM	Wet FGD ("throwaway" systems - double alkali, lime/limestone; sodium)
	Spray drying
	Dry Injection
	Fuel cleaning and blending
NO_x	LEA Staged combustion FGR Low-NO_x burners

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[a] These technologies are evaluated in subsequent chapters with regard to their environmental, cost, and energy impacts on existing boilers converted to COM-firing.

- regenerable wet FGD processes (SO_2),
- alkaline fuel additives (SO_2),
- ammonia injection (NO_x),
- flue gas treatment (NO_x and SO_2/NO_x).

Sidestream separators and mechanical collectors were not selected for further evaluation due to lack of data demonstrating their ability to achieve typical "oil-only" PM emission levels [43 ng/J (0.1 lb/10^6 Btu) or less].

Regenerable FGD processes were considered too complex and costly for retrofit to existing oil-fired boilers converted to COM. The more common "throwaway" wet FGD systems (double alkali, lime/limestone, and sodium throwaway) were selected as more practical for retrofit situations.

Although alkaline fuel additives may be highly suitable for retrofit applications, the data gathered so far are inadequate to characterize the SO_2 control effectiveness of the technique and, more importantly, to evaluate the negative impacts on long-term boiler operation (i.e. slagging and corrosion). Because the process has only been tried in short-term tests on relatively small boilers, it is difficult to accurately quantify the environmental impacts (SO_2 reductions, increased ash with soluble sodium compounds) and the cost impacts (amount of reagent required, effects on boiler operation and maintenance costs). The use of alkaline fuel additives appears somewhat promising, however, especially with regard to its suitability for retrofit due to minimal equipment requirements. The impacts of dry injection of sodium compounds, which was selected for further evaluation due to its relatively more advanced development stage, should provide an approximation of the impacts of using sodium- based alkali fuel additives.

Ammonia injection and the various flue gas treatment were not selected for further evaluation because they are in the very early stages of commercial application and it is difficult to quantify their environmental and cost impacts. Also, these processes are likely to be relatively costly and difficult to retrofit to existing boilers.

A detailed discussion of the environmental impacts of the technologies shown in Table 3.7-1 is presented in Chapter 4, and Chapter 5 presents cost impacts.

3.8 REFERENCES

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CHAPTER 4

ENVIRONMENTAL IMPACTS OF CONTROL TECHNOLOGIES

This chapter discusses the environmental impact of various particulate matter (PM), SO_2, and NO_x control technologies for boilers firing COMs. The environmental impacts of the technologies were evaluated in terms of: (1) the effectiveness of the technology in controlling one or more of the criteria air pollutants (PM, SO_2, NO_x), (2) secondary environmental impacts of the technology, including liquid and solid wastes, and (3) the effectiveness of the technology in controlling trace elements (As, Be, Cd, Cr, Hg, Mn, Ni, Se, and V).

4.1 SUMMARY OF ENVIRONMENTAL IMPACTS

The evaluation of the environmental impacts of control technologies for COM combustion was based primarily on data and information from existing applications of the technologies to coal- and oil-fired boilers. However, differences between COM combustion and coal- or oil-firing that may impact the performance of the technology were identified and the qualitative effects of the differences were evaluated.

Table 4.1-1(a-c) summarizes the environmental impacts of several control technologies. These technologies were selected in Chapter 3 as likely candidates for application to industrial and utility boilers converted to COM-firing. As discussed in Chapter 2, the boilers that have the greatest potential for converting to COM are existing oil-fired boilers. In many cases, these boilers are subject to emission regulations designed for oil-fired units and the increased emissions from COM pose significant environmentally-related questions. Table 4.1-1a denotes the capability of the various technologies to reduce criteria pollutants (PM, SO_2, and NO_x) to the levels typical of oil-fired units subject to existing air emission regulations. (See Section 2.3 - Regulatory Requirements.)

This section provides a summary of the environmental impacts. A more detailed discussion is presented in Sections 4.2 through 4.5.

PM Control

High particulate matter control efficiencies (98 percent or greater) have been widely demonstrated with ESPs, fabric filters, and wet scrubbers. In general, these technologies can reduce fly ash emissions to 43 ng/J (0.1 $lb/10^6$ Btu) or less, a level comparable to controlled and, in many cases, uncontrolled fly ash emissions from oil-fired boilers. Fabric filters are generally the most effective of the three technologies. Bag blinding (caking of moist particulate matter on the filter bag), mentioned

TABLE 4.1-1. ENVIRONMENTAL IMPACTS OF CONTROL TECHNOLOGIES FOR COM COMBUSTION

Table 4.1-1a. Emission Reduction Capability of Candidate Control Technologies

Control Technology	COM Emissions Control[a]			Comments
	PM[b]	SO_2	NO	
Fabric Filters	99+% removal; 0.05 lb/10^6Btu or less.	-[c]	-	Can reduce PM emissions to "oil-only" levels or less.
Electrostatic Precipitators (ESP)	99+% removal; 0.1 lb/10^6Btu or less.	-	-	Effectiveness depends on adequate collection plate area. Lack of COM fly ash resistivity data. With proper design, can reduce PM emissions to "oil-only" levels or less.
Wet Scrubber (venturi-type)	Up to 90% removal; 0.1 lb/10^6Btu	-[c]	-	Can reduce PM emissions to "oil-only" levels. Produces wet sludge for disposal; possible liquid waste impacts.
Wet FGD (Sodium throwaway, dual alkali, lime, limestone)	Up to 98+% removal; 0.1 lb/10^6Btu	90% removal	-	Can reduce SO_2 and PM emissions to "oil-only" levels. Potentially large amounts of sludge for disposal depending on boiler size, SO_2 removal. Potentially significant liquid waste impacts for sodium throwaway. Reduced plume dispersion without reheat.
Spary drying FGD (lime sorbent; includes fabric filter or ESP)	99+% removal; 0.05 lb/10^6Btu or less.	Up to 90% removal	-	Can generally reduce SO_2 and PM emissions to "oil-only" levels. SO_2 removal may be less for high sulfur COMs.
Dry injection FGD (sodium-based alkali; includes fabric filter)	99+% removal; 0.05 lb/10^6Btu or less.	Up to 90% removal	-	Can generally reduce SO_2 and PM emissions to "oil-only" levels. SO_2 removal may be less for high sulfur COMs. Potentially more severe solid waste impacts due to solubility of sodium-based wastes.
Physical coal cleaning	10 to 60% reduction in coal ash content	20 to 40+% reduction in potential SO_2 emissions	-	Can achieve SO_2 levels of "oil-only" depending on final coal sulfur, oil sulfur, and percent coal in COM. Will likely require additional PM control.

TABLE 4.4-1. (Continued) ENVIRONMENTAL IMPACTS OF CONTROL TECHNOLOGIES FOR COM COMBUSTION

Table 4.1-1a. (Continued) Emission Reduction Capability of Candidate Control Technologies

Control Technology	COM Emissions Control[a]			Comments
	PM[b]	SO	NO	
Oil hydrodesulfurization	Some reduction in oil ash content	Up to 90% removal	-[d]	Can achieve "oil-only" SO_2 levels depending on coal sulfur and percent coal in COM. Will likely require additional PM control due to contribution of coal ash to COM emissions.
Low NO_x burners[e]	-	-	Reductions vary with burner type, design and with COM composition	Has been shown to achieve NO_x levels equal to or less than oil-only in limited laboratory tests.
Staged Combustion[e]	-	-	30 to 40% reduction in NO_x.	Effective in reducing fuel NO_x. Not likely to achieve oil-only levels in all cases.
Low Excess Air[e]	-	-	10 to 20% reduction in NO_x.	Not likely to achieve "oil-only" NO_x levels. Effectiveness depends on COM properties and boiler design.
Flue Gas Recirculation[e]	-	-	Difficult to quantify because of variability in limited data.	Can possibly achieve "oil-only" levels when used in combination with staged combustion.

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[a] Control capability described in terms of removal efficiency and/or controlled emission rates achievable.

[b] To convert lb/10^6 Btu to ng/J, multiply by 430.

[c] Fabric filters used in dry injection and spray drying systems to achieve PM control; Wet scrubbers used in FGD systems for combined SO_2/PM control.

[d] HDS may reduce nitrogen content of oil slightly, but depending on percent coal in COM it may not significantly reduce NO_x emissions from COM combustion.

[e] Reductions based on limited testing of COM combustion.

Table 4.1-1b. Potential Secondary Environmental Impacts of Control Technologies for COM Combustion

Control Technology	Type and Nature of Wastes Dry Solid	Sludge	Liquid	Other Potential Environmental Impacts
Fabric Filters	Dry fly ash; established disposal techniques such as landfilling are environmentally acceptable.	-	-	-
Electrostatic Precipitators (ESP)	Same as fabric filter	-	-	-
Wet scrubbers (PM only)	-	Water/fly ash sludge; environmentally acceptable disposal techniques.	Potential during process upset.	Cooling of flue gas reduces plume dispersion; could cause increase ground level concentrations of SO_2 and NO_x without reheat.
Wet FGD (Sodium)	-	-	Liquid waste dissolved sodium salts; may require waste-water treatment or evaporation ponds.	Cooling of flue gas; reduced plume dispersion without reheat.
Wet FGD (dual alkali, lime,	-	Calcium-based in 30-60% solid sludge; landfilling, ponding are environmentally acceptable disposal methods. Commercial utilization may be possible.	Should be minimal with closed-loop operation	Cooling of flue gas; reduced plume dispersion without reheat.
Spary drying (lime sorbent)	Fly ash and calcium-based solids; landfill disposal	-	-	Some cooling of flue gas, but not as much as with wet FGD because flue gas is not saturated.
Dry injection (sodium sorbents)	Fly ash and sodium-based salts; high solubility of solids may require specialized disposal methods.	-	-	-
Physical Coal Cleaning	No boiler-site impacts if COM obtained from central preparation facility.			PCC plants covered by existing environmental regulations for fugitive emissions, water, and other impacts.

Table 4.1-1b. (Continued) Potential Secondary Environmental Impacts of Control Technologies for COM Combustion

Control Technology	Type and Nature of Wastes Dry Solid	Sludge	Liquid	Other Potential Environmental Impacts
Oil Hydrodesulfurization	No boiler-site impacts			-
NO_x Combustion Modifications (LEA, SC, FGR, low-NO_x burners)	-	-	-	May result in high CO, unburned hydrocarbons emissions if not properly operated. Problems can be eliminated or minimized with automatic oxygen control systems.

Table 4.1-1c. Trace Element Control Capability of Control Technologies for COM Combustion

Control Technology	Control of Trace Elements in Classes 2 & 3[a]	Control of Trace Elements in in Class 4[b]
Fabric filters[c]	99+% removal of trace elements	Less control than for Class 2 and 3 elements.
ESP	95+% in many cases.	Less control than for Class 2 and 3 elements.
Wet scrubber[d]	95+% based on limited data. May be less efficient than fabric filters or ESPs.	Possible improved control over fabric filters or ESPs, since gas becomes saturated.
PCC	About 10 to 75% depending on coal type, PCC process and type of trace element.	25 to 52% depending on coal type, PCC process.
HDS	Up to 95% removal of Ni and V reported.	-

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[a] Class 2 and Class 3 elements are those elements that tend to be enriched on smaller fly ash particles (As, Be, Cd, Cr, Ni, Se, V)

[b] Class 4 trace elements are those that tend to remain in the vapor phase. (Hg, Se)

[c] Also applies to spray drying and dry injection systems using a fabric filter.

[d] Applies to wet scrubbers used for PM-only or combined SO /PM removal.

in some literature as a potential problem due to the hygroscopic nature of the fly ash, has not been observed in limited COM experience. In fact, the fly ash from COM combustion appears to have characteristics similar to coal fly ash. Coal fly ash has been shown to be highly suitable for fabric filter collection. With proper design (i.e. adequate specific collection plate area), ESPs can be as efficient as fabric filters. However, there is currently a lack of resistivity data on COM fly ash, data which may be particularly important for boilers firing a COM made from low sulfur coal. It is likely that the resistivity properties of the coal fly ash will dominate the characteristics of the COM ash.

Wet scrubbers are somewhat less effective than fabric filters or ESPs, especially with regard to collection of submicron particles. Venturi-type scrubbers are generally the most efficient type of scrubber for PM removal. Wet scrubbers, however, have two main disadvantages: (1) they result in wet solids sludge and may have liquid waste impacts and (2) the flue gas becomes saturated, reducing plume buoyancy and adversely affecting dispersion of gaseous pollutants (SO_2 and NO_x).

Combined SO_2/PM Control

In general, the technology exists to control SO_2 from COM combustion to levels equal to or lower than those from existing oil-fired boilers. Flue gas desulfurization (FGD) systems, which are capable of achieving at least 90 percent SO_2 removal, are the most effective SO_2 control technologies. However, significant SO_2 control can also be obtained by:

- using dry FGD technology (spray drying, dry injection) to achieve 50 percent or more SO_2 removal from a low-sulfur COM; or
- preparing a COM with physically cleaned coal, hydrodesulfurized oil, or naturally occurring low sulfur fuels.

The method of blending cleaned fuels (or naturally occurring low sulfur fuels) to make the COM has the advantage of avoiding any of the boiler-site solid or liquid waste impacts associated with FGD control.

Wet scrubbers are quite suitable for combined SO_2 and PM removal. Combined SO_2/PM control with this system favors venturi-type scrubbers, possibly preceeded by a mechanical collector. Substantial combined SO_2/PM control is also achievable with spray drying systems (which include a fabric filter or an ESP) and with dry injection of sodium- based alkali compounds into a fabric filter. The disposal of highly soluble sodium-based wastes from dry injection may present more serious solid waste disposal problems than the disposal of calcium-based wastes from spray drying or wet FGD systems.

Physical coal cleaning (PCC) can reduce the ash content of the coal as well as reducing its sulfur content. But, depending on the percentage of coal in the COM and the final ash content of the cleaned coal, combustion of COM made from PCC will still likely require additional control to reduce PM emissions to levels typical of oil combustion.

NO_x Control

Despite the use of what are generally accepted as the most efficient technologies applicable to COM units, NO_x emissions from COM combustion may still be greater than those from combustion of typical No. 6 residual oils. Low-NO_x burners are the most effective of the candidate NO_x control technologies selected in Chapter 3. Limited data indicate that low-NO_x burners can reduce NO_x emissions to "oil-only" levels or less. However, for high nitrogen content COMs, NO_x emissions may still be above the levels prescribed in some emission regulations, particularly in states like California which have stringent NO_x regulations. In addition, the development status of low-NO_x burners for commerical utility and industrial boilers firing COM is somewhat questionable (See Chapter 3). Staged combustion is a relatively effective NO_x control technology. This technique reduces fuel NO_x formation and is thus particularly suitable for high nitrogen content COMs, the combustion of which produces substantial amounts of fuel NO_x. Staged combustion has been shown to achieve reductions in NO_x emissions of from 30 to 40 percent during COM combustion tests. Operation at low excess air (LEA) levels is primarily effective in reducing thermal NO_x. Available data from LEA tests during COM combustion show NO_x reductions of 10 to 20 percent. Thus, it is likely that more than just LEA control would be required for high nitrogen COMs to reduce NO_x emissions to the levels typical of oil combustion.

It should be noted that the effects of such variables as COM properties, the presence of water in the COM, combustion air preheat temperatures, and boiler heat release rate on NO_x emissions from COM combustion are not fully quantifiable based on existing data. Also, boiler-to-boiler variations in burner and furnace design may result in significant variations in NO_x emissions from combustion of a given COM.

Trace Element Control

The technologies that achieve the greatest degree of fine particulate control are the most efficient for trace element collection, since many of the trace elements tend to be enriched on the smaller fly ash particles. Thus, fabric filters achieve the greatest degree of trace element control, followed by ESPs and wet scrubbers. Physical coal cleaning and oil hydrodesulfurization can reduce trace element concentration in the fuel prior to combustion.

4.2 PARTICULATE MATTER (PM) CONTROL TECHNOLOGIES

This section discusses the emission reduction capability of three PM control technologies: ESPs, fabric filters, and wet scrubbers (no SO_2

removal). Any potential secondary environmental impacts associated with the use of these technologies are identified. Differences between the fly ash produced during COM combustion and that produced during coal-only or oil-only combustion are also discussed.

An important factor in evaluating the emission reduction capability of PM control technologies is their efficiency in collecting small particles; that is, particles less than about 10 micrometers in diameter. As discussed earlier (in Chapter 3), a large percentage of the fly ash produced during COM combustion is less than 10 micrometers (mean particle diameter). In general, fabric filters are the most efficient collectors of small particles, followed by ESPs. Wet scrubbers are the least efficient of the three, especially with regard to very fine particulate matter (less than 2.5 micrometers). Figure 4.2-1 provides a useful comparison of the (theoretical) fractional efficiencies of several PM control technologies.

4.2.1 Electrostatic Precipitator (ESP)

4.2.1.1 Pollutant Control Capability.

Electrostatic precipitators can be designed to achieve overall collection efficiencies as high as 99.9 percent. However, very high collection efficiencies or collection of high resistivity particles requires large collector plate areas, with the attendant increase in ESP cost.

Precipitators applied to coal-fired industrial and utility boilers have been shown[1,2] to be capable of reducing emissions to 43 ng/J (0.1 lb/10^6 Btu) or less. The 1979 NSPS applicable to utility coal-fired boilers specifies an emission limit of 13 ng/J (0.03 lb/10^6 Btu), based on the use of an ESP or a fabric filter. Several tests on utility oil-fired boilers with ESPs have also shown controlled emissions of less than 43 ng/J (0.1 lb/10^6 Btu).[4]

Particle (fly ash) resistivity and inlet grain loading can have a significant effect on ESP performance. In retrofitting a new ESP to an existing boiler that is being converted to COM, the resistivity of the COM fly ash should be measured prior to ESP design. The measurements will help insure that adequate collection plate area is provided to achieve the desired control level. Such measurements may be particularly important for COM mixtures made with large percentages of low sulfur coal; the fly ash from low sulfur coal tends to have high resistivity and large collector areas may be required for high collection efficiencies.

The performance of an existing ESP designed for oil-firing may be quite different during COM firing. If the COM fly ash resistivity is significantly higher than the resistivity of oil fly ash, the ESP may have to be modified to achieve the same level of control. Similarly, the increase in inlet grain loading (uncontrolled particulate emissions) associated with COM may require ESP modification.

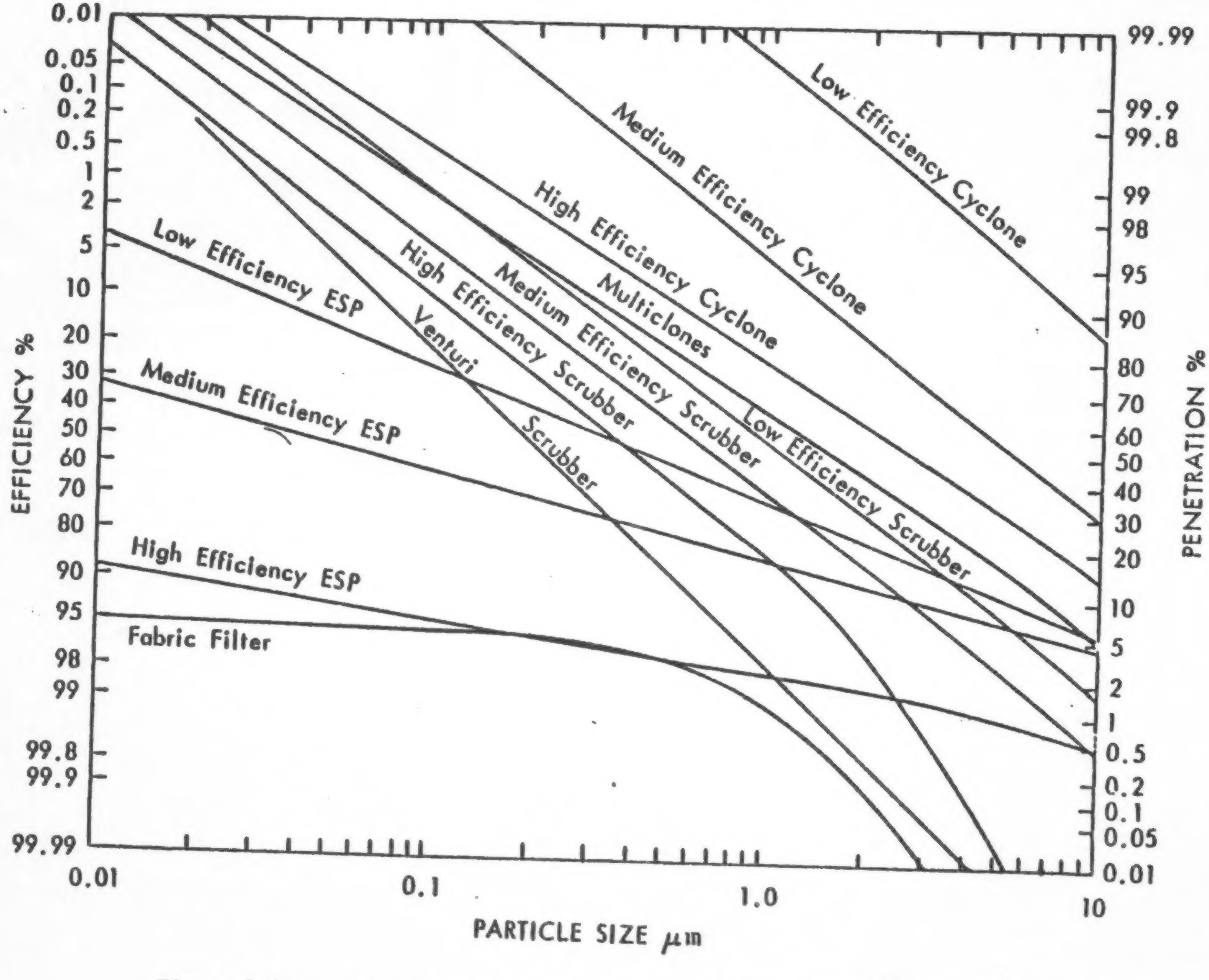

Figure 4.2-1. Comparison of control device fractional efficiencies.[3]

Significant changes during boiler operation in the COM fuel properties that affect inlet loading or particle resistivity are likely to impact ESP performance.

4.2.1.2 Secondary Environmental Impacts

Collection of fly ash by ESPs results in a dry solid waste. The primary method of fly ash disposal is landfilling, either at the plant site or in centralized off-site landfills. When properly designed and operated, landfills present no adverse environmental impact. With proper landfilling techniques, potential leaching and runoff problems can be minimized and the site eventually reused for recreational or building purposes.[5] Alternatives to landfill disposal include commercial utilization of fly ash in road embankments, concrete mixtures, or sludge stabilization.

As discussed in Chapter 2, fly ash from both coal- and oil-fired boilers has received a "non-hazardous" designation under current EPA solid waste regulations. Thus, current state and local regulations, generally formulated under EPA guidelines, will govern the landfill disposal practices.

4.2.2 Fabric Filter

4.2.2.1 Pollutant Control Capability

Fabric filters are widely considered to be the most efficient PM control technology for coal-fired boilers and the technology should be equally as efficient for boilers firing COM. Although oil fly ash can be quite hygroscopic and potentially cause bag blinding,[6] fly ash from COM combustion has been found to be dry and powdery, similar to the fly ash from pulverized coal combustion.[7] This fact is attributable to the substantially smaller amount of oil fly ash relative to coal fly ash generated from combustion of a given COM.

Fabric filter collection efficiencies are generally about 99.9+ percent. Several emission tests of fabric filters applied to coal-fired industrial and utility boilers have shown controlled emissions of 21 ng/J (0.05 lb/10^6) or less Btu.[8,9] The same level of control should be achievable on boilers firing COM. In addition, fabric filter performance is relatively insensitive to changes in inlet grain loading and particle size distribution, particle resistivity. Thus, fabric filter performance is not likely to be impacted by even substantial changes in COM properties that might occur at a given boiler.

4.2.2.2 Secondary Environmental Impacts

The solid waste impact associated with fabric filters are basically the same as those discussed for ESPs in Section 4.2.1.2. The only difference may be the larger amount of fly ash collected with a fabric filter [21 ng/J (0.05 lb/10^6 Btu) or less] relative to an ESP specifically designed for a controlled emission level of 43 ng/J (0.1 lb/10^6 Btu). For a 205 MW_t (700 x 10^6 Btu/hr) boiler, the difference between a controlled emission rate of 21 ng/J and 43 ng/J could amount to an additional 3,178 Mg/yr (3,500 ton/yr) of fly ash for disposal.*

4.2.3 Wet Scrubber

4.2.3.1 Pollutant Control Capability

Wet scrubbers, while less efficient than fabric filters or high efficiency ESPs, are still capable of achieving substantial PM emission control. Venturi-type scrubbers, designed for PM control on coal- and oil-fired boilers, are capable of 98+ percent overall removal when operated at relatively high pressure drops [5kPa (20 in. w.g.)]. Emission tests of several industrial and utility pulverized coal-fired boilers have shown wet scrubbers to be capable of reducing emissions to 43 ng/J (0.1 lb/10^6 Btu) or less.[10]

Wet scrubbers have the advantage of serving as a suitable contactor for high SO_2 removals when an alkaline sorbent is dissolved in the scrubbing liquor (See Section 4.3.1). In cases where a coal has large amounts of available alkalinity, substantial SO_2 removal may occur even without the addition of another alkaline chemical.

Wet scrubber particulate matter removal performance is affected by changes in inlet grain loading, and thus may be sensitive to any wide fluctuations in COM properties during operation of a given boiler.

4.2.3.2 Secondary Environmental Impacts

Unlike ESPs and fabric filters, PM collection with wet scrubbers results in wet sludge. The sludge is usually between 30 and 60 percent solids. If the sludge is disposed of in ponds, the potential for leaching and groundwater contamination generally dictate the use of clay-lined ponds. Sludge characteristics and the currently accepted disposal practices are discussed further in Section 4.3.1 (wet FGD systems). Operation of wet scrubbers in a closed-loop manner can minimize any potential liquid waste impacts.

One potential disadvantage of using wet scrubbers is reduced pollutant dispersion, due to the flue gas being cooled to its adiabatic saturation temperature in the scrubber. Depending on local air quality and the applicable regulations, stack gas reheat may be required to assure good plume dispersion.

4.3 COMBINED SO_2/PM CONTROL TECHNOLOGIES

This section presents the environmental impacts associated with five technologies, each providing for combined control of SO_2 and PM:

- wet flue gas desulfurization (wet FGD),
- spray drying FGD,

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*Assuming uncontrolled COM emissions of 860 ng/J (2.0 lb/10^6 Btu) and a 60 percent annual capacity factor.

- dry injection FGD,
- physical coal cleaning (PCC), and
- oil hydrodesulfurization (HDS).

Although each of these techniques are primarily for SO_2 control, they can also achieve moderate to substantial reductions in PM emissions over uncontrolled levels.

The SO_2 and PM reduction capability of each of these technologies is discussed in more detail below. Any potential secondary environmental impacts associated with their use are also examined.

4.3.1 Wet Flue Gas Desulfurization (FGD)

As discussed in Chapter 3, the wet FGD techniques most applicable to coal-, oil-, and COM-fired boilers include dual alkali, lime/limestone, and sodium throwaway. Each of the techniques achieves comparable SO_2 and PM emission reductions. Dual alkali and lime/limestone systems have similar solid and liquid waste impacts, but the liquid waste impacts of the sodium throwaway system are potentially more serious.

4.3.1.1 Pollutant Control Capability

With proper design and operation, wet FGD systems can achieve sustained 90 percent SO_2 removal or greater.[11,12] Continuous SO_2 emission monitoring tests of an industrial boiler limestone FGD system with adipic acid added to the scrubber were recently conducted by EPA. These tests showed a 30-day average SO_2 removal of about 94 percent.[13] Other EPA continuous monitoring tests of dual alkali, lime, and sodium throwaway systems operating on industrial boilers have shown average SO_2 removals of 90 percent or greater.[11] Figure 4.3-1 shows the annual SO_2 emissions (as a function of boiler size) for 3 different sulfur content COMs and 90 percent SO_2 removal. Figure 4.3-2 shows the SO_2 emission rate per unit heat input as a function of SO_2 removal for the three COMs. Uncontrolled SO_2 emissions from high and low sulfur fuel oil combustion are shown for comparision. Figure 4.3-2 shows that except for the 1 percent sulfur COM, 80 to 90 percent SO_2 removal is required to reduce emissions below the uncontrolled levels typical of a 0.4 percent sulfur oil.

Wet FGD systems can achieve high SO_2 removal over a wide range of inlet SO_2 concentrations. Dual alkali systems have been used to treat flue gases with inlet SO_2 concentrations as low as 250 ppm and as high as 3,800 ppm.[14] Sodium throwaway systems have been applied to treat flue gases with inlet SO_2 concentrations ranging from 150 to 2,000 ppm.[15] Lime and limestone systems have also been used across a wide range of SO_2 concentrations. Thus, wet FGD systems can achieve substantial SO_2 reductions from boilers burning COMs with a wide variety of sulfur contents.

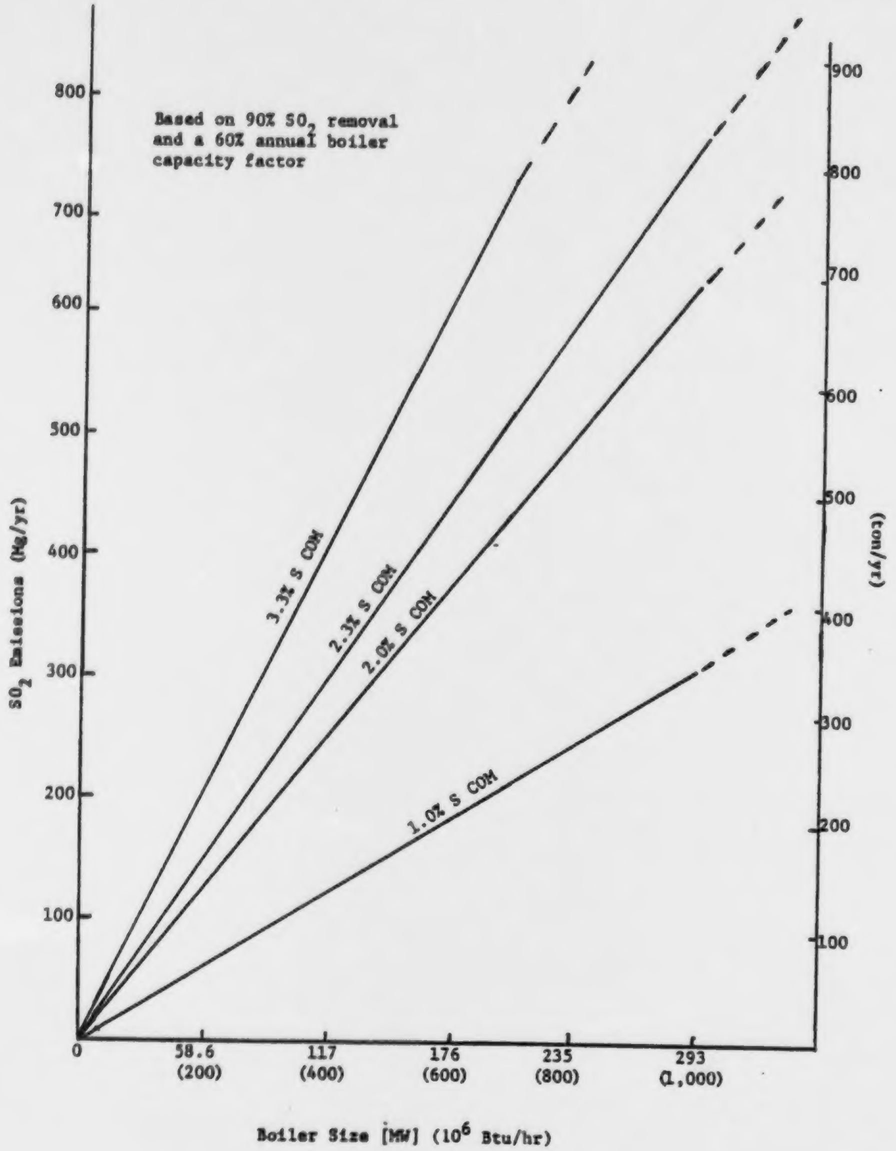


Figure 4.3-1. Annual SO_2 emissions for different COM sulfur contents as a function of boiler size.

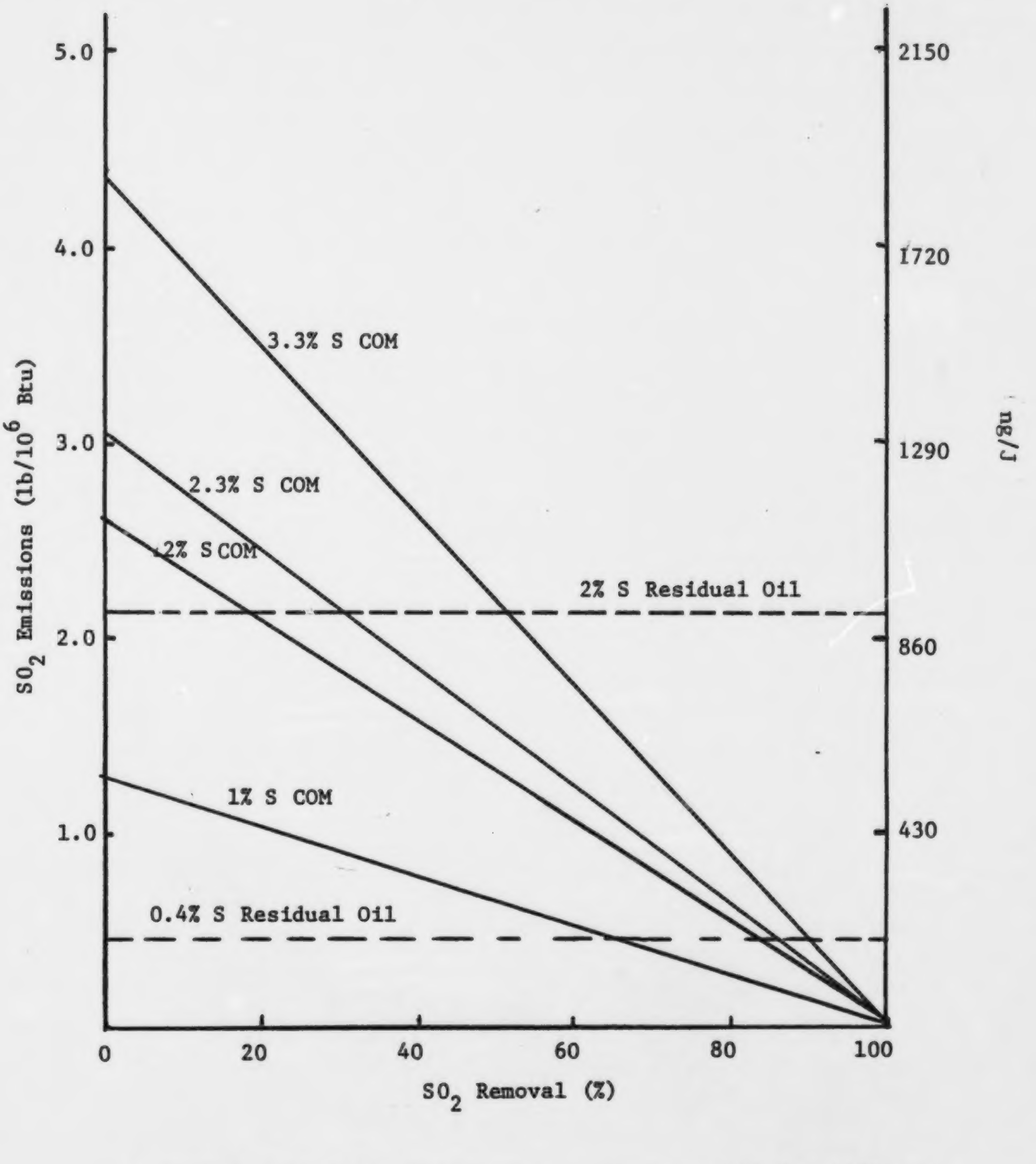


Figure 4.3-2. SO_2 emissions vs. percent removal for different COM sulfur contents.

Variations in inlet SO_2 concentration, process operation, and emission measurement can significantly affect daily average SO_2 removals with wet FGD systems. These considerations may be important for boilers subject to relatively stringent SO_2 regulations. A recently completed EPA study analyzed the impact of such variations on the daily SO_2 removal achievable with industrial boiler wet FGD systems.[16] This study found that even if average sustained SO_2 removal was maintained at 90 percent, 24-hour average SO_2 removal could occasionally drop as low as 65 percent. [Because the study was intended to support possible Federal SO_2 standards, relatively conservative statistical parameters and assumptions were used to calculate this "lower bound" daily SO_2 removal.]

Wet FGD systems can be designed to remove significant amounts of particulate matter. Venturi scrubbers are the preferred design if fly ash is to be removed in the scrubber. As discussed in Section 4.2.3, emission levels of 43 ng/J (0.1 lb/10^6 Btu) or less are achievable with wet scrubbers. Many FGD scrubbers designed for PM removal are located downstream of a mechanical collector. The primary purpose of the mechanical collector is to capture the large fly ash particles before they enter the scrubber. A secondary advantage of the mechanical collector is that it can provide at least some particulate matter control if the FGD scrubber has to be completely bypassed during a malfunction.

It should be noted that if the wet FGD system is not designed to remove fly ash, some type of upstream PM control (usually a fabric filter or an ESP) will be required to assure reliable FGD scrubber operation.[17]

4.3.1.2 Secondary Environmental Impacts

There are three basic secondary environmental impacts associated with the use of wet FGD systems:

- reduced pollutant dispersion due to poor plume buoyancy (if no reheat is used),
- production of sludge waste for disposal, and
- potential water pollution impacts.

The first concern, reduced pollutant dispersion, can be alleviated by using stack gas reheat. EPA has produced a full report on reheat requirements and methods.[18] The report concluded that 28 to 56°C (50 to 100°F) of reheat leads to substantial reductions in ground level NO_x and SO_2 concentrations relative to scrubbed gas without reheat. However, even with tall stacks and 56°C (100°F) of reheat, maximum ground level concentrations of NO_x were predicted to be greater than from unscrubbed flue gas. In every case, however, ground level concentrations of SO_2 and NO_x were predicted to be below the applicable standards.

Lime, limestone, and dual alkali wet FGD systems produce sludge waste which generally contains 35 to 60 percent solids. The sludge is composed primarily of calcium sulfite and sulfate salts. Significant amounts of fly ash may also be present. The sludges are relatively inert and with proper site selection and disposal practices, they can be disposed of in an environmentally acceptable manner. The currently practiced methods include lined and unlined ponding and landfilling of treated and untreated sludge. Potential adverse impacts of sludge disposal lie in the areas of disposal acreage requirements, groundwater contamination through leaching, and percolation of soluble components of the solid waste. Treatment techniques to minimize adverse impacts include sludge dewatering, addition of alkaline fly ash (fixation), and/or application of commercial stabilization techniques. These techniques are used to decrease the volume of sludge, decrease its permeability and improve its structural properties.[19]

Figure 4.3-3 shows the annual sludge production rates for a dual alkali FGD system (operating at 90 percent SO_2 removal) as a function of boiler size for four different sulfur content COMs. The rates are based on a 60 percent annual capacity factor, a 60 percent solids waste, and do not include fly ash.

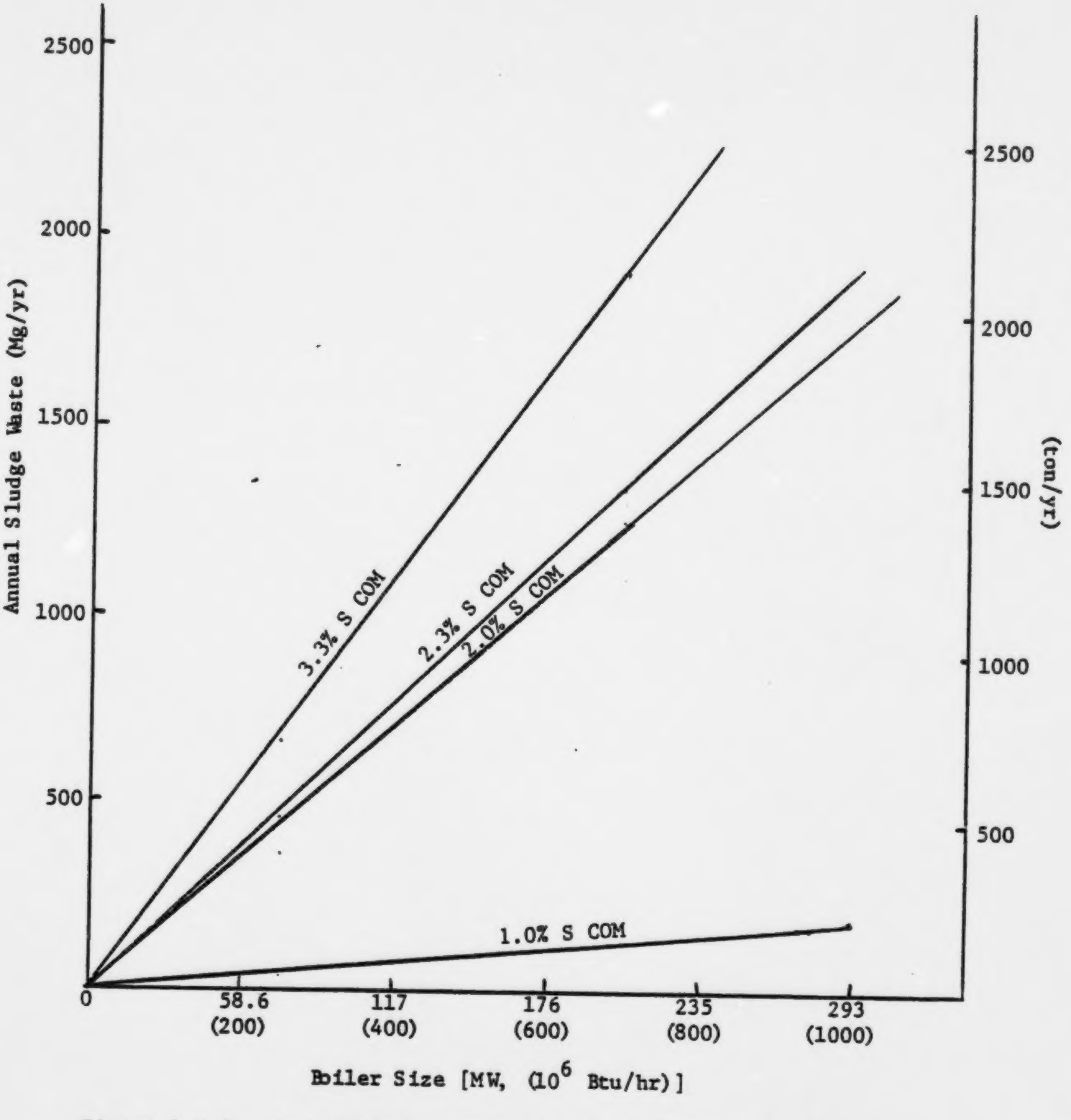
The most severe water pollution impacts are associated with the use of sodium throwaway systems. Good design and operating practice for dual alkali, lime, and limestone systems includes dewatering the sludge and recycling the supernant liquid.[20] Operation in this "closed-loop" manner should prevent liquid waste emissions during normal process operation of these systems. The aqueous waste stream from the sodium throwaway process contains dissolved sodium sulfate and sulfite salts. This stream must be treated in an individual or centralized wastewater treatment facility before being discharged to municipal sewer systems. An alternative to wastewater treatment is to discharge the liquid waste stream to an evaporation pond, though the use of this technique may be limited to low rainfall climates.

4.3.2 Spray Drying FGD

4.3.2.1 Pollutant Reduction Capability

Spray dryers (using lime sorbent) have been shown in pilot-scale demonstration tests and limited commercial operating experience to achieve up to 90 percent SO_2 removal. To date, however, most SO_2 removal data have been limited to instances where the inlet SO_2 concentration was 2,500 ppm or less.[21] High SO_2 removal generally requires recycle of the waste solids (to improve SO_2 removal and reduce fresh sorbent consumption) and requires that the spray dryer be operated at a relatively close approach to saturation [about 11°C (20°F)].

Although a few industrial systems have been sold for use on high sulfur coal-fired boilers (3 percent sulfur coal or greater), no commercial operating performance data are available. Most of the 11 utility spray drying systems sold to date, none of which are fully operational, have SO_2



Based on 60% Solids sludge from desulfurization system; 90% SO_2 removal; 60% annual boiler capacity factor.

Figure 4.3-3. Annual sludge production for 90% SO_2 removal as a function of boiler size for different sulfur content COMs.

removal guarantees of 60 to 80 percent.[21] In general, the utility systems will be treating flue gas from low sulfur coal units (about 1.5 percent sulfur or less).

Continued research and development and commercial operating experience should provide better definition of the SO_2 removal achievable with spray drying. At the present time, however, it is difficult to draw documented conclusions about spray drying SO_2 removal in high sulfur fuel applications.

Significant PM control is achieved with the fabric filter or, in some instances, the ESP, that is part of the spray drying system. (Fabric filter and ESP performance were discussed in Section 4.2).

4.3.2.2 Secondary Environmental Impacts

The secondary environmental impacts associated with spray drying are (1) reduced plume buoyancy due to cooling of the flue gas and (2) production of solid waste for disposal.

In the spray dryer the flue gas is cooled to within 11 to 28°C (20 to 50°F) of its adiabatic saturation temperature, and thus plume buoyancy and pollutant dispersion are reduced relative to untreated gas. However, the flue gas is not saturated as it is in wet FGD system. In addition, if lower SO_2 removals are required, some of the flue gas can be bypassed around the dryer to reheat the exitting stack gas.

The solid waste produced in a lime spray drying system is a mixture of calcium sulfite, calcium sulfate, unreacted calcium carbonate, and fly ash, with generally less than 5 percent moisture. Disposal methods applicable to fly ash and wet FGD sludge are also suitable for spray dryer solids. Commercial utilization of the waste solids as a road-base or cement additive is also being investigated.[22]

4.3.3 Dry Injection

4.3.3.1 Pollutant Control Capability

Dry injection of sodium-based alkali compounds into SO_2-laden flue gas passing through a fabric filter has been shown to achieve substantial SO_2 removal in pilot-scale tests. There are no full-scale commercial dry injection systems.

Dry injection of sodium-based alkalis such as trona, nahcolite, and commercial sodium bicarbonate, has been shown to achieve SO_2 removals of between 60 and 90 percent.[23] The highest SO_2 removals have been achieved with nahcolite and commercial sodium bicarbonate.

Dry injection was used in DOE tests of the COM pilot facility located at the Pittsburgh Energy Technology Center. Up to 90 percent SO_2 removal was obtained during firing of a low sulfur COM (1 percent sulfur).

Dry injection can also achieve significant PM control since the technology is based on the use of a fabric filter.

4.3.3.2 Secondary Environmental Impacts

The solid waste impacts of sodium-based dry injection are potentially severe. The highly leachable sodium salts produced could result in groundwater contamination if they are not disposed of properly. Disposal in a clay-lined landfill may be acceptable, provided the wastes are encapsulated in cells with clay-lined top, bottom, and sides. The clay liner must be selected carefully to avoid choosing one that may be susceptible to breakdown or swelling under such high-sodium conditions.

4.3.4 Physical Coal Cleaning (PCC)

4.3.4.1 Pollutant Control Capability

The effectiveness of PCC in reducing the sulfur content of coal depends on the "washability" characteristics of the coal. Physical coal cleaning can reduce potential SO_2 emissions from coal by about 10 to 60 percent. The actual reductions depend on the type of PCC process used and the nature of the sulfur compounds in the coal.[24] Sulfur reductions of 20 to 30 percent are achievable for many coals. Coals with high percentages of sulfate and pyritic sulfur are the most suitable for large sulfur reductions by PCC. Table 4.3-1 shows typical SO_2 emission reductions by PCC for selected U. S. coals.

Figure 4.3-4 shows the estimated uncontrolled SO_2 emissions from COMs made from high and low sulfur fuel oil and coals of different sulfur contents. These figures show the influence of reducing the sulfur content of the coal (a process which generally increases the heating value of the coal) as a function of the percent coal in the COM. Uncontrolled emissions from 100 percent oil-firing are shown for comparison. Figure 4.3-4a shows that a COM made from 2 percent sulfur residual oil and coal with a sulfur content of less than about 1.5 percent will have lower SO_2 emissions that the 2 percent residual oil at any coal concentration. Figure 4.3-4b shows that for any coal concentration, emissions from COM made with low sulfur oil (0.8 percent S) will be higher than the oil SO_2 emissions if the coal sulfur exceeds about 0.5 percent.

Physical coal cleaning also reduces the ash content of the coal. As shown in Table 4.3-1, reductions in ash content can range from 10 percent [for relatively low ash run-of-mine (ROM) coals] to 63 percent [for high ash ROM coals]. Reducing the ash content of the coal used to make a COM reduces the uncontrolled PM emissions from combustion of the COM. However, the COM emissions will still be greater than uncontrolled fly ash emissions from oil-firing and additional PM control is likely to be required.

4.3.4.2 Secondary Environmental Impacts

There are no boiler-site environmental impacts associated with use of PCC in COMs, although there are solid and liquid waste impacts associated

TABLE 4.3-1. SULFUR AND ASH REDUCTION OF PCC FOR SELECTED U. S. COALS[25]

Supply Region	Coal Seam; County, State[a]	Potential SO_2 Emissions ($lb/10^6 Btu$)[b]			Ash Content (%)		
		ROM Coal[d]	Cleaned Coal	% Reduction[c]	ROM Coal[d]	Cleaned Coal	% Reduction[c]
Northern Appalachia	Upper Freeport; Butler, PA (3)	5.99	2.30	62	23.9	9.7	59
	Lower Kittanning; Cambria, PA (3)	2.75	1.72	37	12.8	8.7	32
	Upper Freeport; Butler, PA (2)	5.99	3.41	43	23.9	14.4	40
	Bakerstown; Tucker, WV (4)	1.71	1.35	22	28.7	19.9	31
Central Appalachia	Clintwood; Dickensen, VA (4)	1.25	1.15	8	11.2	8.1	28
	Upper Cliff; DeKalb, AL (2)	1.23	1.06	14	10.9	9.5	10
	Splash Dam; Dickensen, VA (4)	2.77	1.77	36	25.9	9.7	63
	Eagle; Buchanan, VA (4)	1.73	1.30	25	10.4	4.7	55
	Hagy; Buchanan, VA (2)	5.04	3.55	30	23.1	15.5	33
Midwest	Illinois No. 6; Williamson, IL (3)	8.89	5.34	40	29.9	11.4	62
	Illinois No. 5; Saline, IL (3)	4.75	2.97	37	16.4	7.5	54
	Illinois No. 5; Saline, IL (4)	4.75	2.75	42	16.4	7.1	57

FOOTNOTES FOR TABLE 4.3-1. SULFUR AND ASH REDUCTION OF PCC FOR SELECTED U. S. COALS[25]

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[a] Numbers in parenthesis denote level of PCC

(1) = Crushing and sizing.
(2) = Coarse size coal benefication.
(3) = Coarse and medium-size coal beneficiation.
(5) = "Deep cleaning" coal beneficiation.

[b] To convert $lb/10^6$ Btu to ng/J, multiply by 430.

[c] $$\% \text{ Reduction} = 1 - \frac{\text{Total potential } SO_2 \text{ emissions of COM or ash in ROM Coal}}{\text{Total potential } SO_2 \text{ emissions of COM or ash in cleaned coal}}$$

[d] ROM coal = run-of-mine coal.

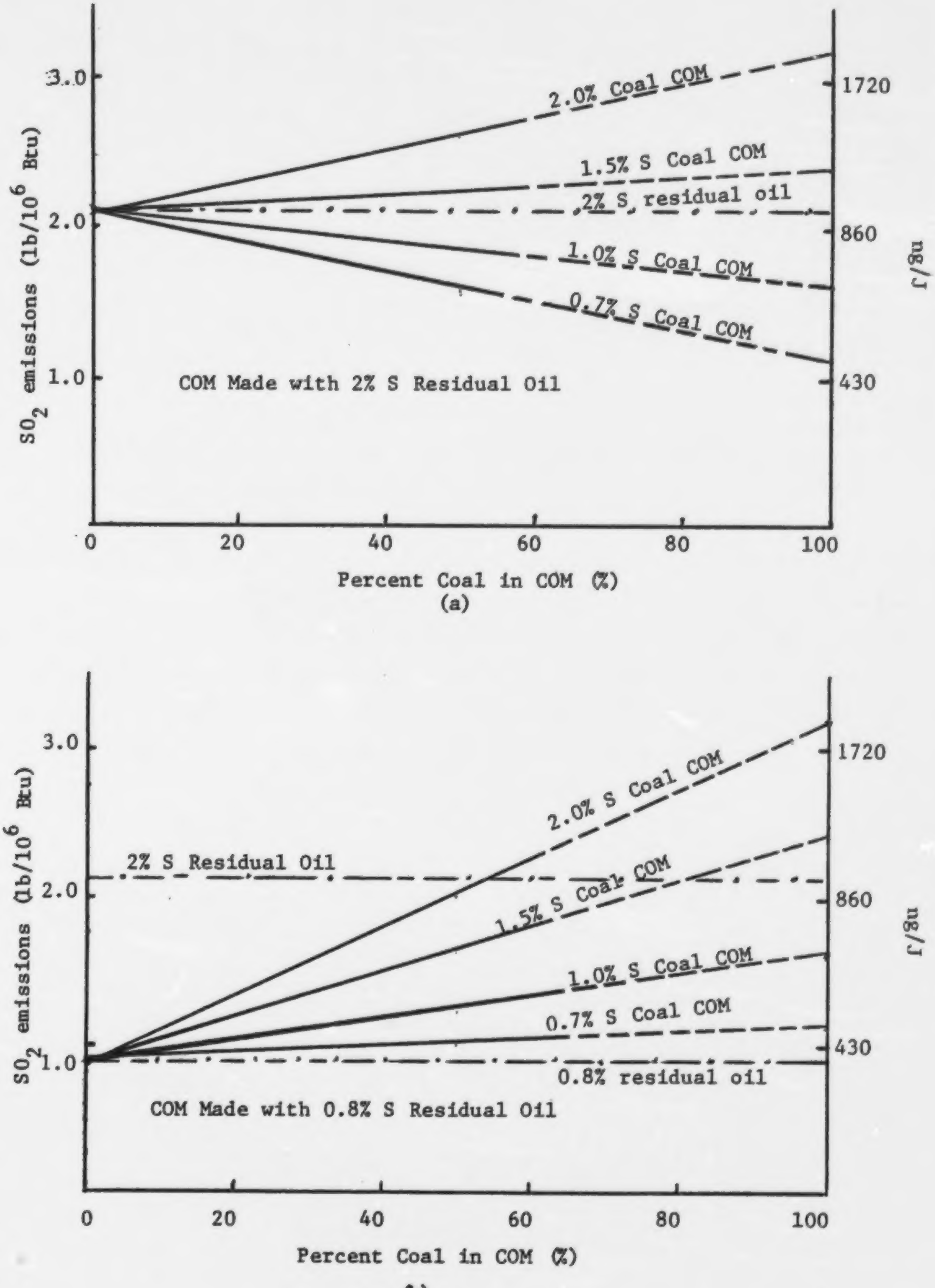

Figure 4.3-4. SO_2 emissions for various COM mixtures as a function of coal sulfur content.*

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*Based on a coal heating value of about 12,000 Btu/lb.

with the PCC process itself. A detailed discussion of PCC solid and liquid waste impacts is outside the scope of this report. However, it should be noted that coal cleaning facilities are subject to EPA standards for air (fugitive emissions) and water quality, and MSHA/OSHA regulations for refuse disposal. A centralized COM preparation facility incorporating a PCC process would also likely be subject to such regulations.

4.3.5 Oil Hydrodesulfurization (HDS)

4.3.5.1 Pollutant Control Capability

Hydrodesulfurization of residual oils can reduce the potential SO_2 emissions of the oil by up to 90 percent. A basic HDS process is capable of producing a product oil with less than 1 percent sulfur from a feedstock oil containing 2 to 3 percent sulfur. Fuel oil with a sulfur content as low as 0.1 to 0.3 percent can be produced with advanced processes, but energy and catalyst consumption for this degree of HDS are relatively high. Important feedstock oil properties that determine the degree of desulfurization practically achievable include density, sulfur content, and metal content. Many refiners now produce a HDS oil with a sulfur content of about 0.8 percent.

Figure 4.3-5 shows the estimated uncontrolled SO_2 emissions of COMs made with various sulfur content oil and high or low sulfur coal. Uncontrolled emissions from 100 percent oil-firing are shown for comparison. Figure 4.3-5a shows that when high sulfur coal is used to make the COM, only small percentages of coal can be used if SO_2 emissions are to be maintained below uncontrolled 0.8 percent sulfur oil levels. Figure 4.3-5b shows that a COM made from 0.3 percent sulfur oil and 1.5 percent sulfur coal has emissions less than those from 0.8 percent S oil up to coal concentrations of about 25 to 30 percent.

Hydrodesulfurization can slightly reduce the ash content and, in some cases, the nitrogen content of the oil. However, these reductions would not have a significant impact on PM and NO_x emissions from combustion of the COM made from the oil since most of the PM and NO_x emissions from COM originate with the coal.

4.3.5.2 Secondary Environmental Impacts

Like the use of PCC in COMs, the use of HDS has no boiler-site secondary environmental impacts. Furthermore, centralized COM preparation facilities would not likely include the HDS process, but would purchase low sulfur oil from existing suppliers.

4.4 NO_x CONTROL TECHNOLOGIES

This section examines four "combustion modification" techniques which can be used to control NO_x emissions from boilers firing COM. The use of low excess air (LEA), staged combustion (SC), flue gas recirculation (FGR), low-NO_x burners, and combinations of these techniques was evaluated with

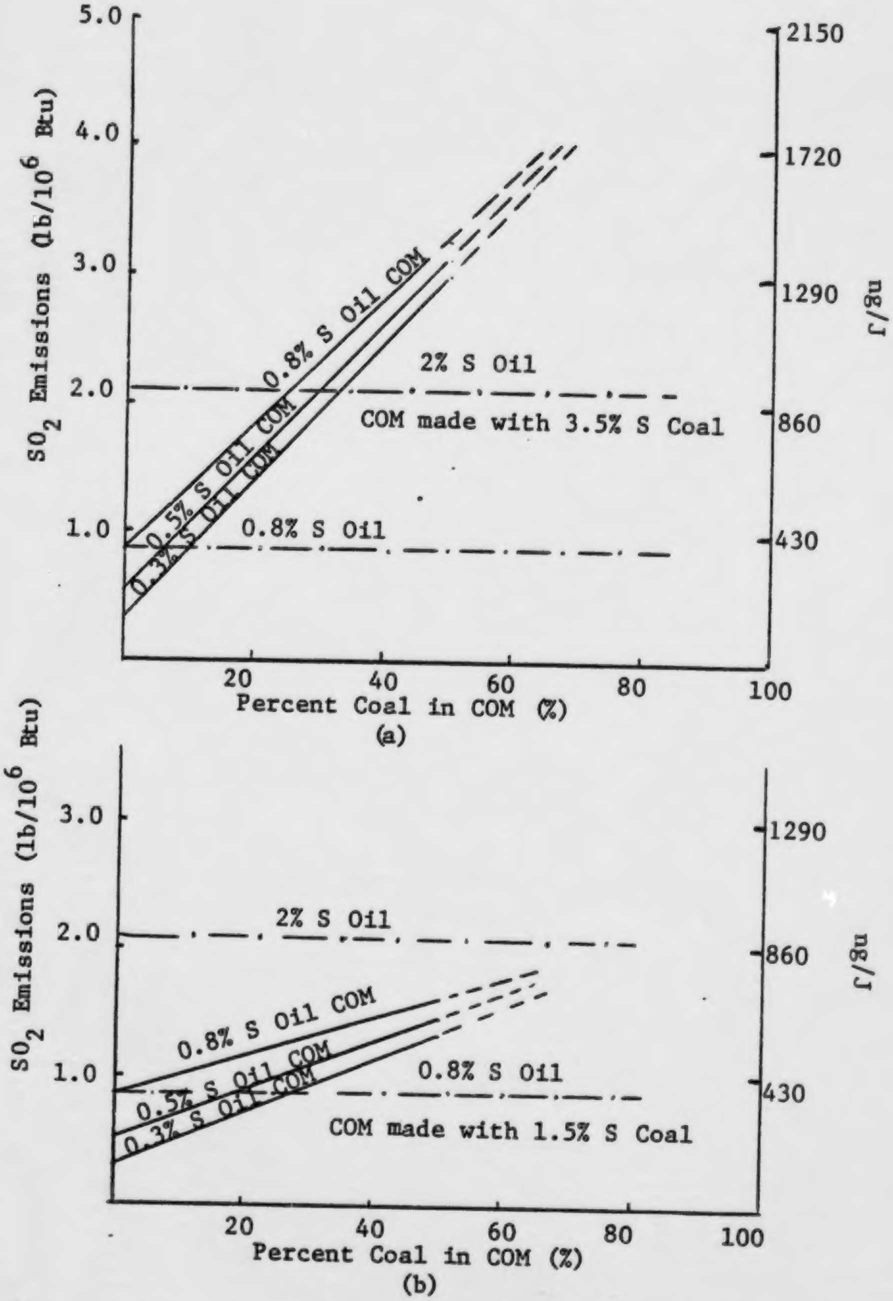


Figure 4.3-5. SO_2 emissions from COM as a function of oil sulfur content for two different coals.

respect to NO_x control capability and any potential secondary environmental impacts that might result from these techniques. (The possible difficulties and limitations associated with using any of these combustion modifications on existing oil-fired boilers converted to COM were discussed in Chapter 3.) In the following sections, the effectiveness of each of the techniques in controlling NO_x emissions is characterized in two ways (1) reduction from uncontrolled NO_x levels typical of COM combustion and (2) the amount of controlled NO_x emissions from COM relative to controlled and uncontrolled NO_x emissions from oil-only firing.

Burner and furnace design can have a significant impact on NO_x emissions from both COM and oil combustion. Because of the high degree of variability in burner and furnace design in existing boilers, it is difficult to characterize the effectiveness of NO_x combustion modification controls for all boilers to which the techniques might be applied. In addition, the amount and controllability of NO_x emissions from COM- firing depends strongly on the properties of the coal and oil used to make the COM and on the composition and properties of the COM itself. Finally, there is a relatively limited amount of data on NO_x control for COM combustion. Direct transfer of data from NO_x control for coal-only and oil-only combustion may not accurately characterize the NO_x reductions achievable during COM combustion. The evaluation of NO_x control techniques presented here is based on limited available test data for COM combustion. The existing NO_x control data base is somewhat limited with respect to the number of tests, quantification of fuel and boiler design effects, and effects of water or other stabilization additives on NO_x emissions. These and other areas of NO_x formation and control are likely to require further investigation before accurate predictions on the effectiveness of the NO_x control techniques can be made for a given boiler and COM.

4.4.1 Low Excess Air

4.4.1.1 Pollutant Control Capability

Figures 4.4-1 through 4.4-3 show the effects of low excess air (LEA) operation on NO_x emissions from COM and oil-only combustion. The data shown in Figures 4.4-1 and 4.4-2 were collected in a laboratory furnace (1.8×10^6 Btu/hr) designed to represent typical industrial boiler heat release rates.[26] The data in Figure 4.4-3 were collected during tests of a nominal 20×10^6 Btu/hr cylindrical furnace in Japan.[27]

Figure 4.4-1 shows reductions of from 10 to 20 percent with a decrease from 40 percent excess air to 20 percent excess air. Figure 4.4-1a also shows that even at 20 percent excess air, NO_x emissions from COM were generally higher than NO_x emissions from oil-only firing. This trend is also shown in Figure 4.4-2, which is a plot of NO_x emissions versus percent coal in the COM for two different excess air levels. Figure 4.4-2 shows that COM NO_x emissions are generally lower at lower excess air levels, but that NO_x emissions from 25 to 50 percent coal COM were greater than for oil-only combustion.

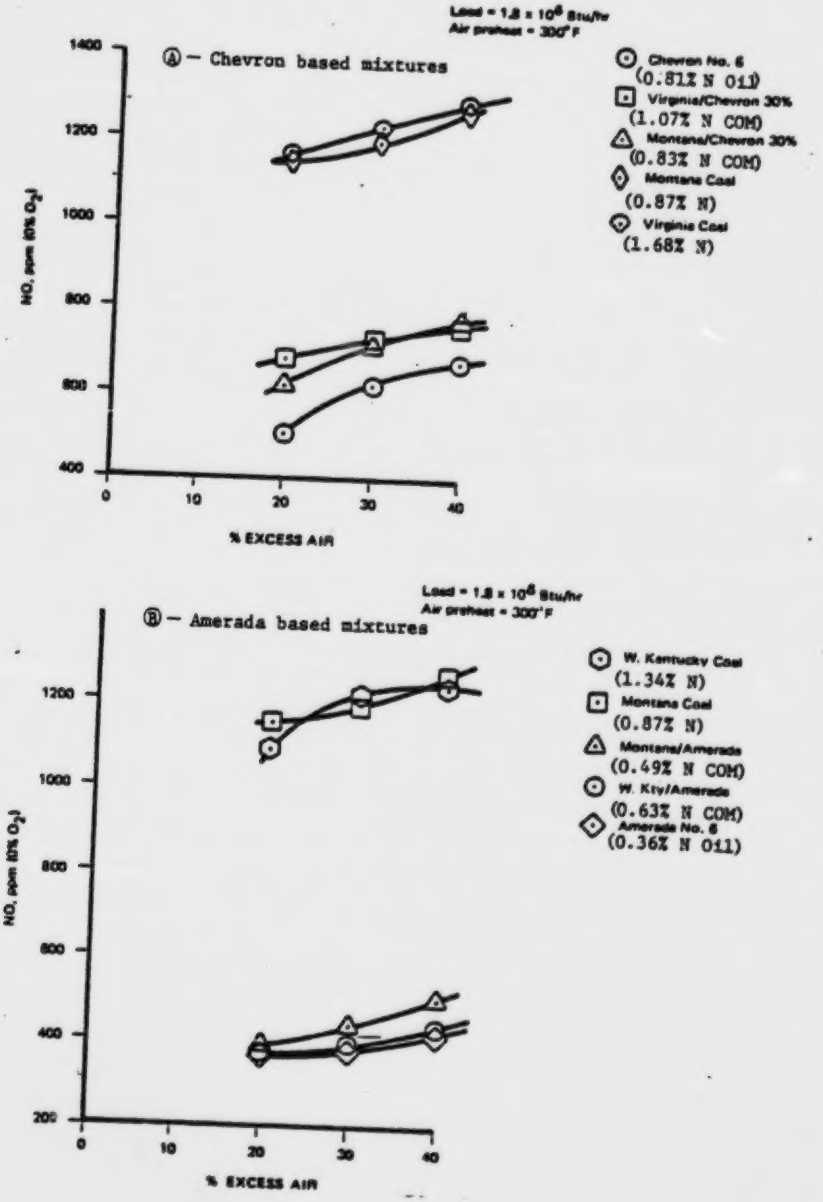


Figure 4.4-1 Influence of excess air level on NO_x emissions from coal, oil, and COM combustion. (Reference 26).

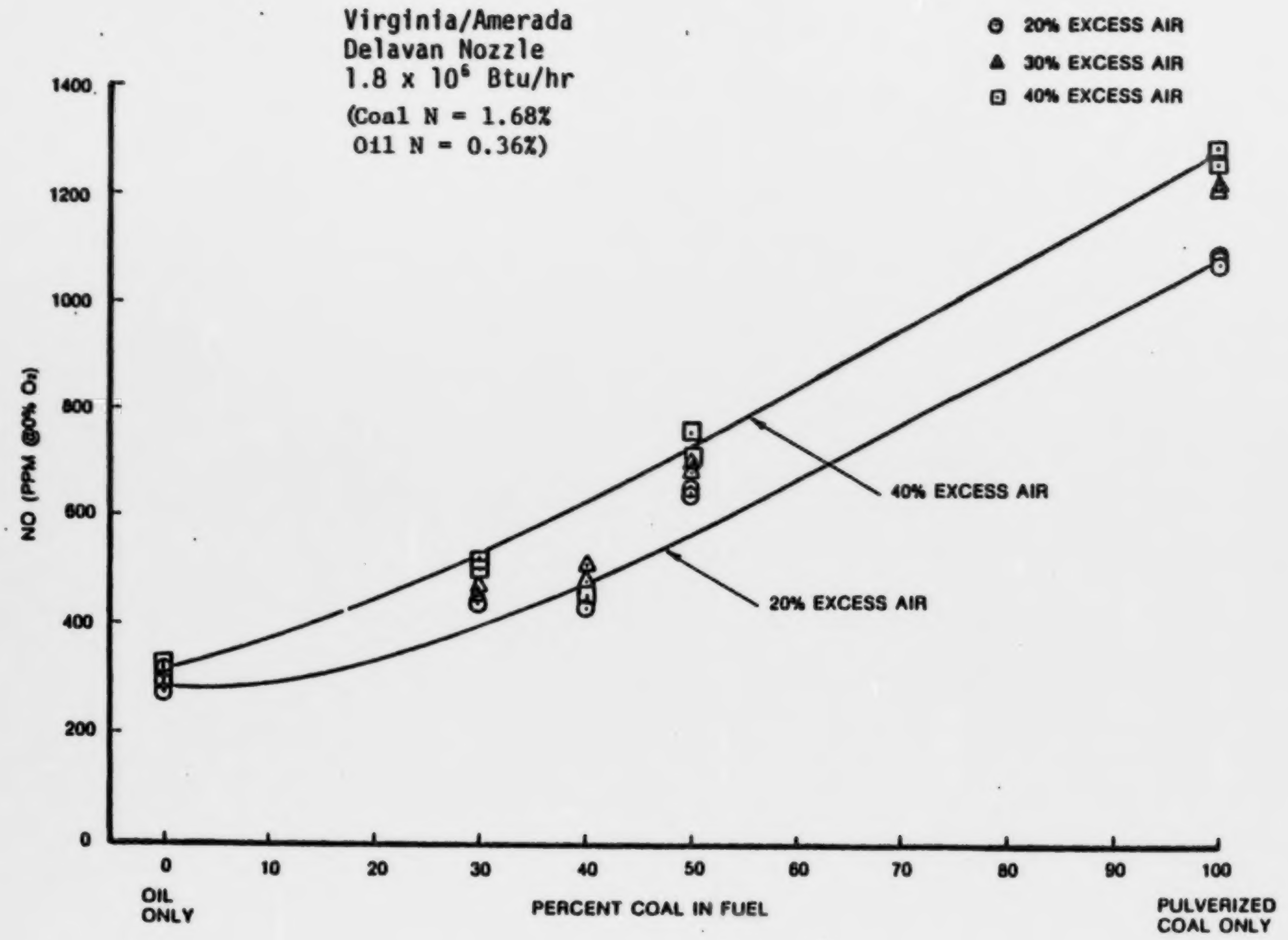


Figure 4.4-2. Influence of excess air and percent coal in COM on NO_x emissions. (Reference 26).

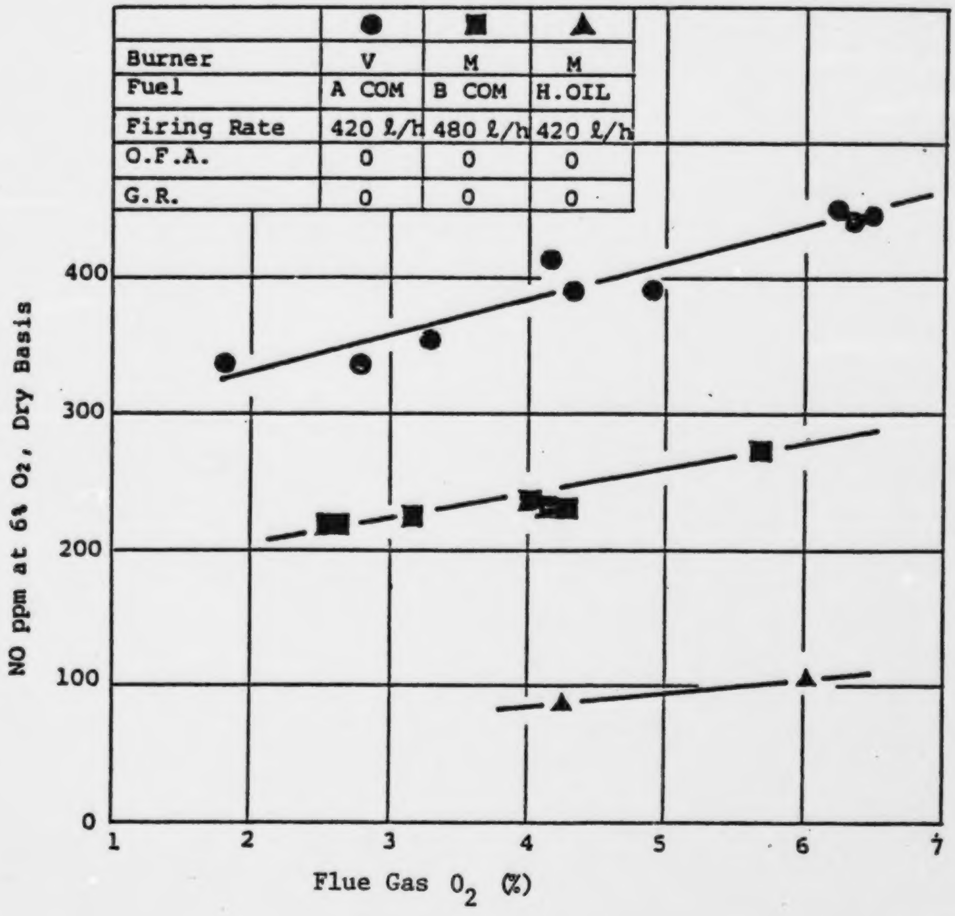


Figure 4.4-3. Influence of excess air on NO_x emissions from COM and oil combustion. (Reference 27).

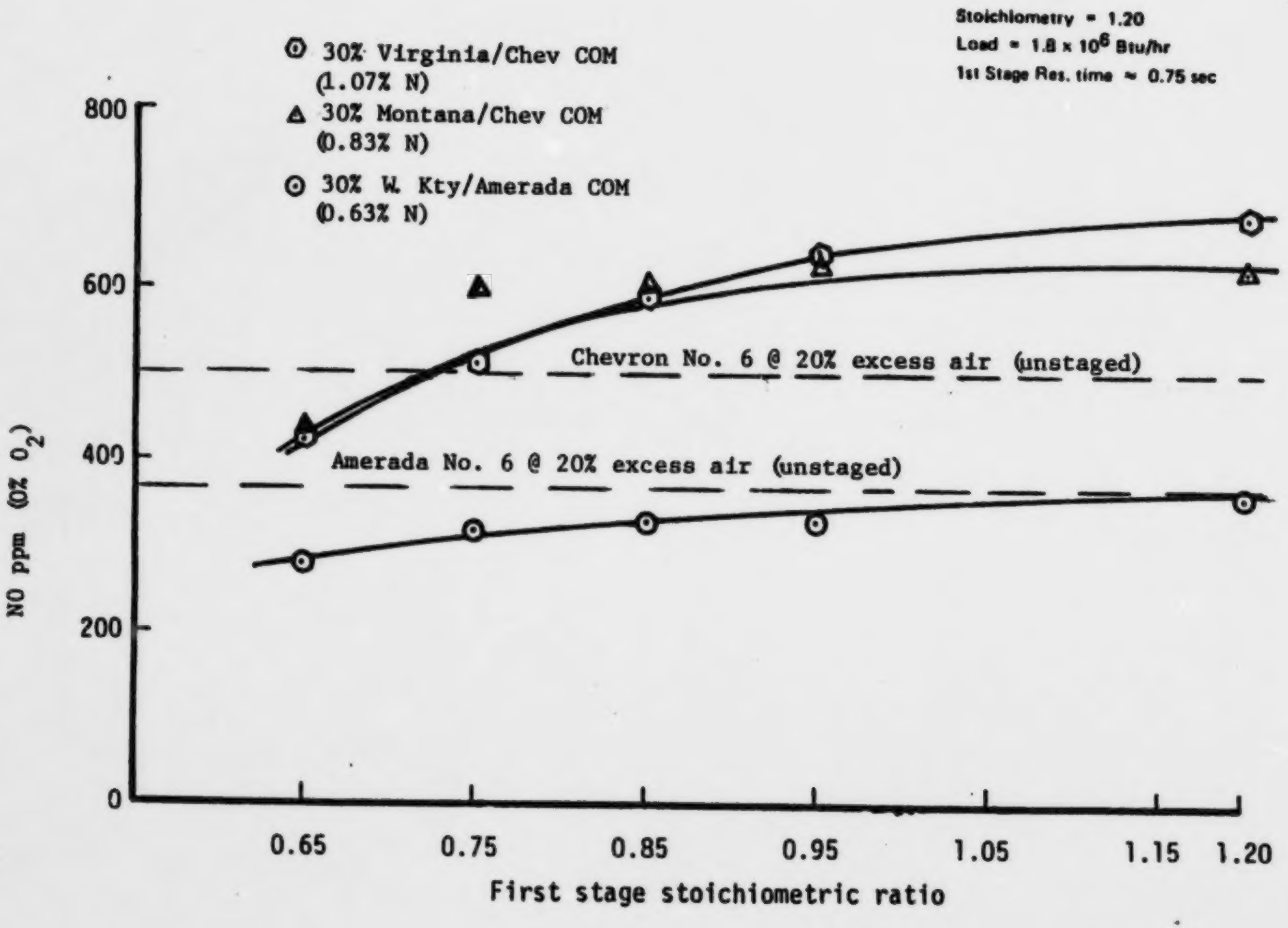


Figure 4.4-4. Staged combustion control of NO_x emissions from COM. (Reference 26).

Figure 4.4-3 also shows some of the trends discussed above. NO_x emissions decrease by 18 to 22 percent as the flue gas oxygen level is decreased from 6 to 3 percent (30 to 15 percent excess air). Again, combustion of COM showed higher NO_x emissions than oil-only combustion, even at low excess air levels.

Thus, based on somewhat limited test data, it appears that about 10 to 20 percent reduction in COM NO_x emissions is achievable with low excess air controls, but that even at LEA levels NO_x emissions from COM combustion are greater than from oil-only combustion.

4.4.1.2 Secondary Environmental Impacts

Although there are no solid or liquid waste impacts associated with LEA operation, reduced excess air levels affect the combustion process and combustion efficiency. Improper control of low excess air operation can result in incomplete combustion, which can in turn lead to increased carbon monoxide, unburned hydrocarbon, and smoke emissions. Incomplete combustion may also result in increased polycyclic organic matter (POM) emissions.[28] However, with an automatic oxygen control system, these potential problems are minimized or eliminated, and LEA should not have any secondary air pollution impacts.[29]

4.4.2 Staged Combustion

4.4.2.1 Pollutant Control Capability

Staged combustion, which involves reducing flame zone oxygen concentration, is effective in reducing fuel NO_x formation. Figures 4.4-4 and 4.4-5 show results of staged combustion testing at two sites. Data in Figure 4.4-4 were obtained on the same laboratory furnace as those shown in Figures 4.4-1 and 4.4-2. Data in Figure 4.4-5 were obtained at the same facility as data in Figure 4.4-3. The nominal 5.9 MW (20×10^6 Btu/hr) test furnace was a horizontal cylindrical furnace designed for staged combustion. Figure 4.4-4 shows that NO_x emissions from the higher nitrogen COM combustion are reduced by about 30 to 40 percent when the stoichiometric ratio of air at the burner is decreased from 1.2 to 0.65. Staged combustion had less impact on NO_x emissions from the lower nitrogen West Kentucky COM. All tests were conducted at an excess air level of about 20 percent. NO_x emissions from 20 percent excess air unstaged combustion of the two oils from which the COMs were prepared are shown in Figure 4.4-4 for comparison. The data show that staged combustion reduces NO_x emissions from COM below oil-only levels only at very low stoichiometric ratios.

Figure 4.4-5 shows NO_x reductions of 36 to 38 percent for staged combustion. These reductions were achieved by injecting about 18 percent of the combustion air through downstream ports. Figure 4.4-5 shows controlled COM NO_x levels to be higher than oil-only NO_x emissions under either staged or unstaged conditions. The difference between COM and oil-only NO_x emissions under staged conditions 18 percent over-fired air (OFA) is reduced relative to the difference at unstaged conditions (0 percent OFA).

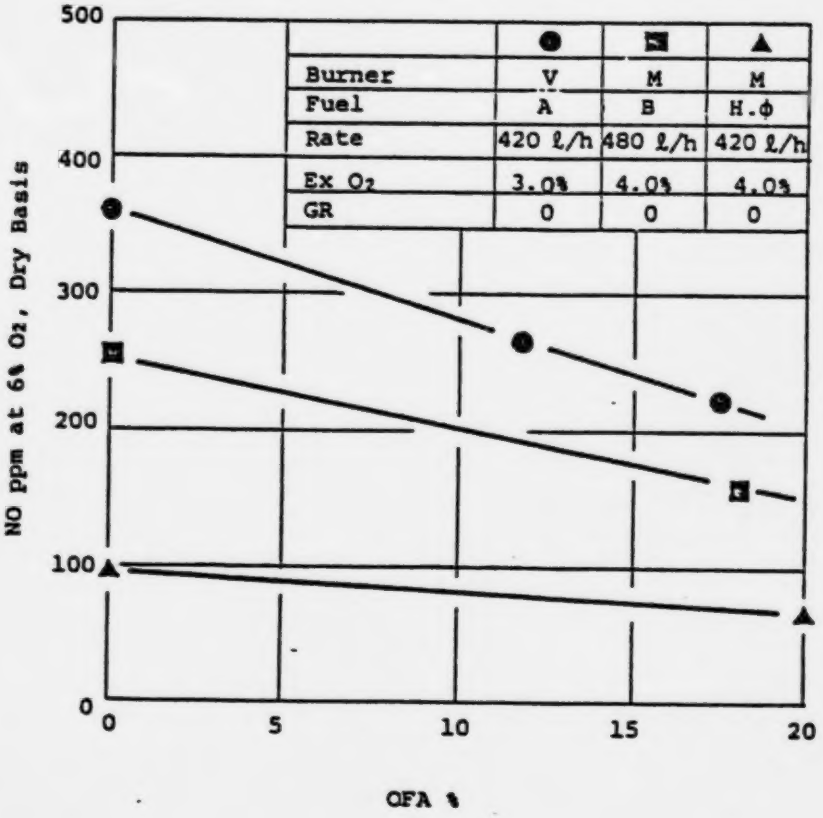


Figure 4.4-5. Staged combustion control of NO$_x$ emissions from COM. (Reference 27.)

4.4.2.2 Secondary Environmental Impacts

The potential secondary environmental impacts of staged combustion are similar to those of LEA. That is, improper combustion air flow control can lead to incomplete combustion and higher levels of CO, unburned hydrocarbons, or smoke. However, proper air flow control will eliminate or minimize any potential adverse impacts.

4.4.3 Flue Gas Recirculation (FGR)

4.4.3.1 Pollutant Control Capability

Figures 4.4-6a through c show controlled and uncontrolled NO_x emissions from an 80 x 10^6 Btu/hr test burner. The burner was tested in three different utility boilers to evaluate the effectiveness of flue gas recirculation (FGR), used alone or in combination with staged combustion.[30] Although there is substantial scatter in the data and the number of tests is limited, the results generally show FGR to be effective in reducing NO_x emissions from COM combustion, particularly when it is used in combination with staged combustion. Figure 4.4-6c shows COM NO_x emissions to be below oil-only levels in two tests of FGR/staged combustion. However, Figure 4.4-6b shows FGR/staged combustion to be only slightly more effective than staged combustion alone.

Figure 4.4-7 also shows data for combined FGR/staged combustion tests. Data are shown for 18 percent staged air at flue gas recirculation rates of 10 to 18 percent. Emissions from oil-only combustion with FGR/staged combustion controls are also shown in Figure 4.4-7.

4.4.3.2 Secondary Environmental Impacts

Potential secondary impacts of FGR are similar to those discussed above for LEA and staged combustion.

4.4.4 Low NO_x Burners

4.4.4.1 Pollutant Control Capability

Figure 4.4-8 shows the results of laboratory low-NO_x burner tests for three different COMs. Emissions of NO_x are shown as a function of the stoichiometric ratio in the fuel tube (see sketch). "Baseline" NO_x emissions at 20 percent excess air are shown for each of the three COMs and for each of the two oils from which the COMs were prepared. (These "baseline" emissions are taken from Figure 4.4-1.) Figure 4.4-8 shows that combustion of the COM made with West Kentucky coal in low-NO_x burners results in NO_x levels below uncontrolled NO_x emissions from oil-only firing. NO_x emissions from the Montana coal COM were also less than oil-only levels when the stoichiometric ratio in the fuel tube was less than 0.75. NO_x emissions from combustion of the Virginia coal COM were less than oil-only levels at stoichiometric ratios of 0.65 or less.

Figure 4.4-8 shows the dependence of NO_x control technology effectiveness on COM properties. Each of the three COMs exhibited different

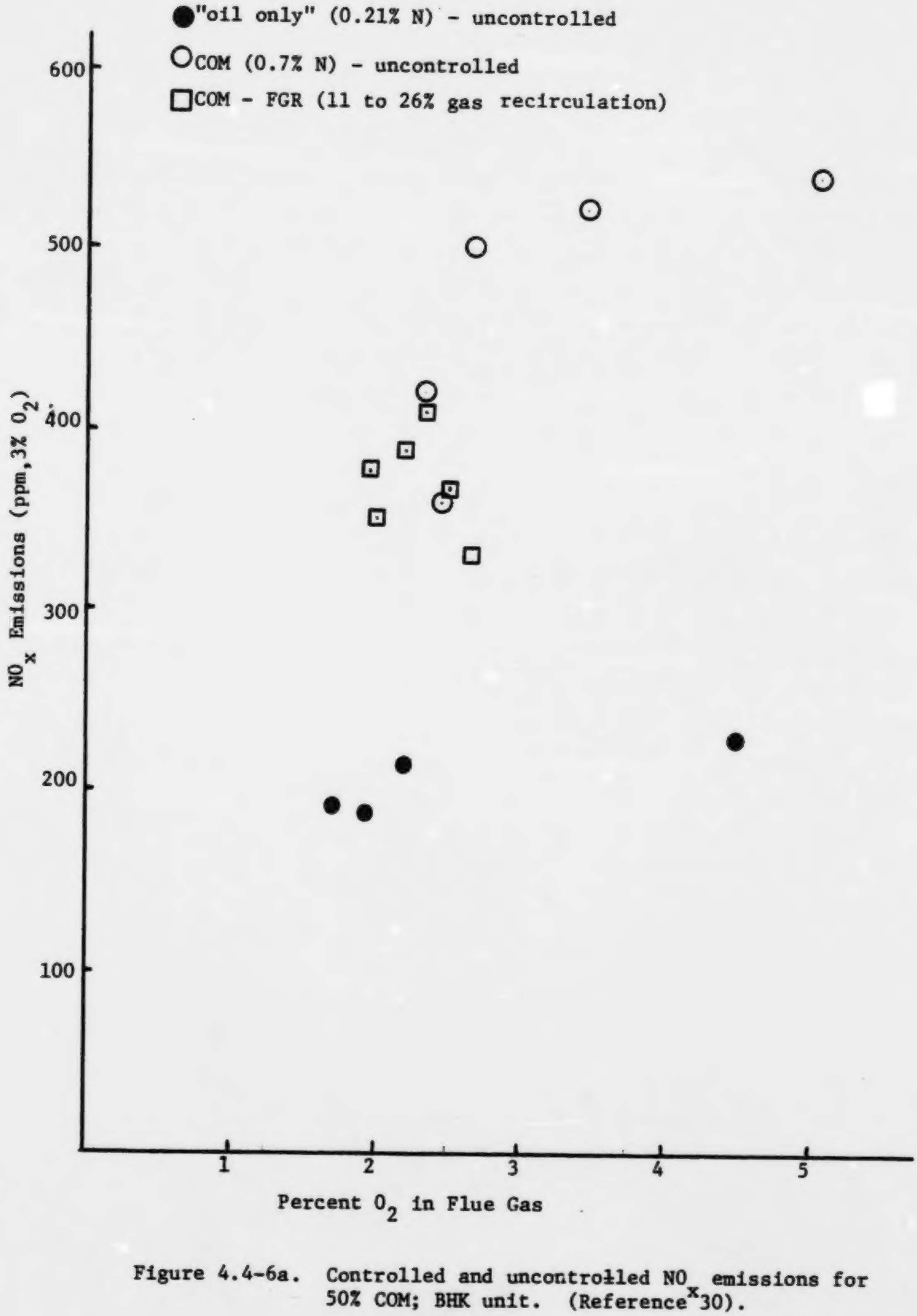


Figure 4.4-6a. Controlled and uncontrolled NO_x emissions for 50% COM; BHK unit. (Reference 30).

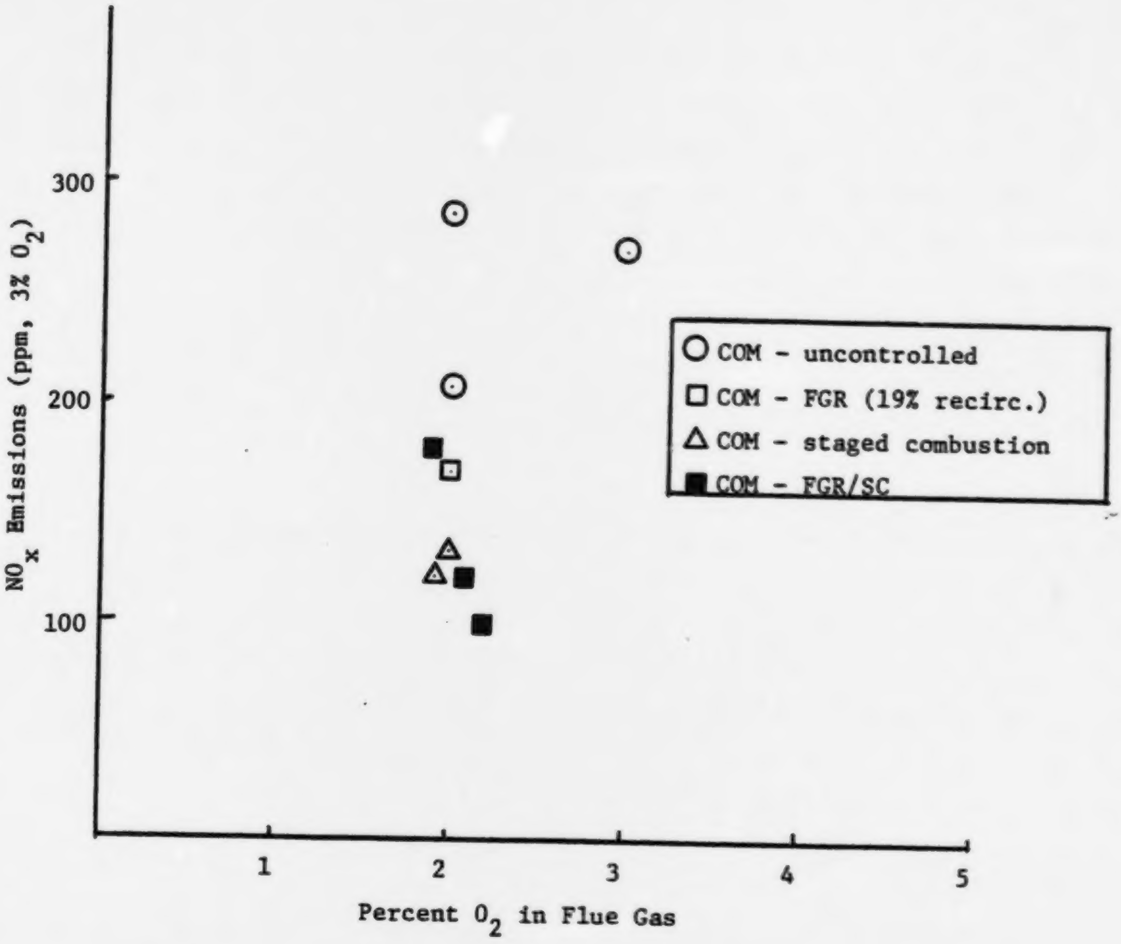


Figure 4.4-6b. Controlled and uncontrolled NO_x emissions for 50% COM; IHI unit. (Reference 30).

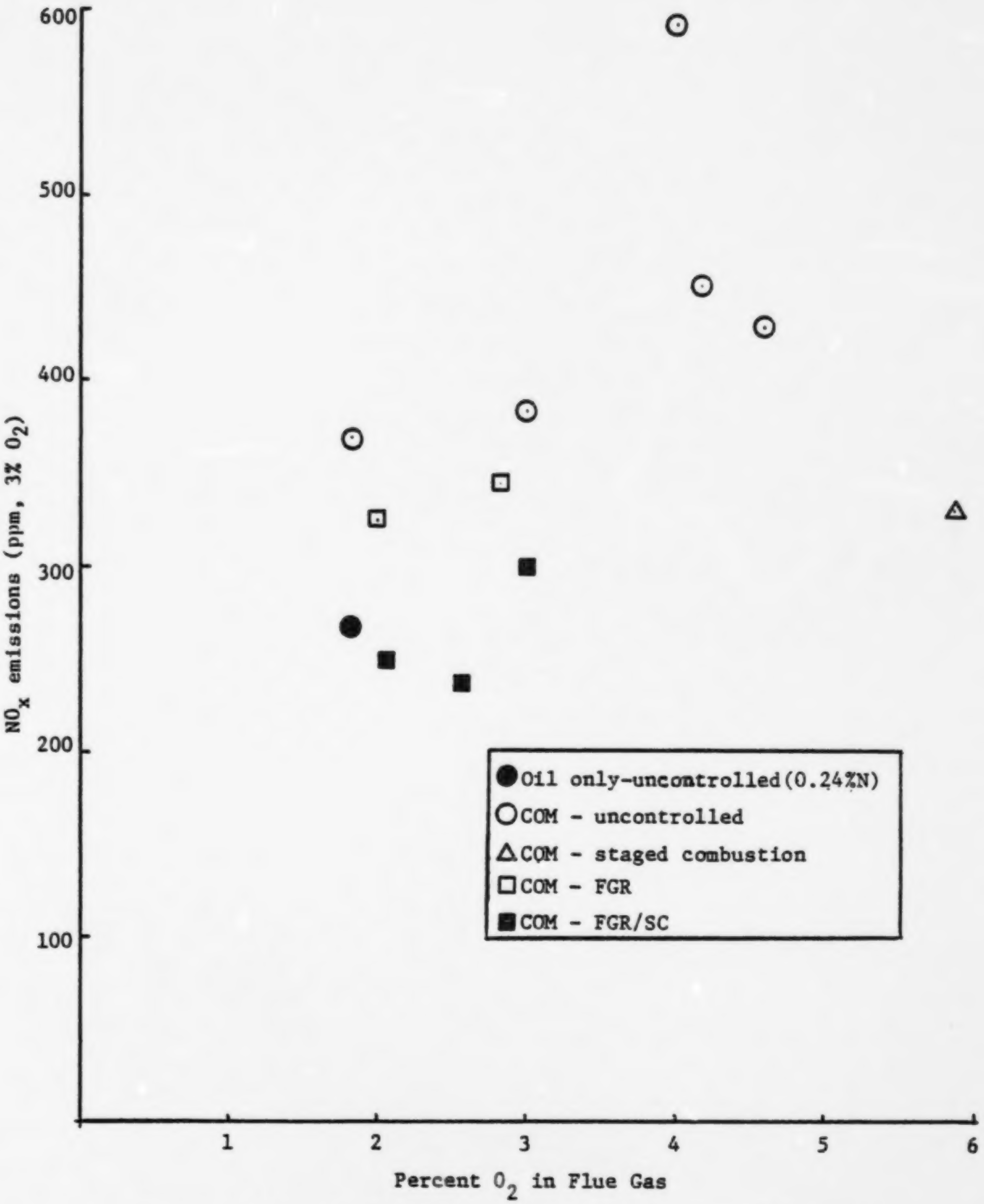


Figure 4.4-6c. Controlled and uncontrolled NO_x emissions from 50% COM; MHI unit. (Reference 30).

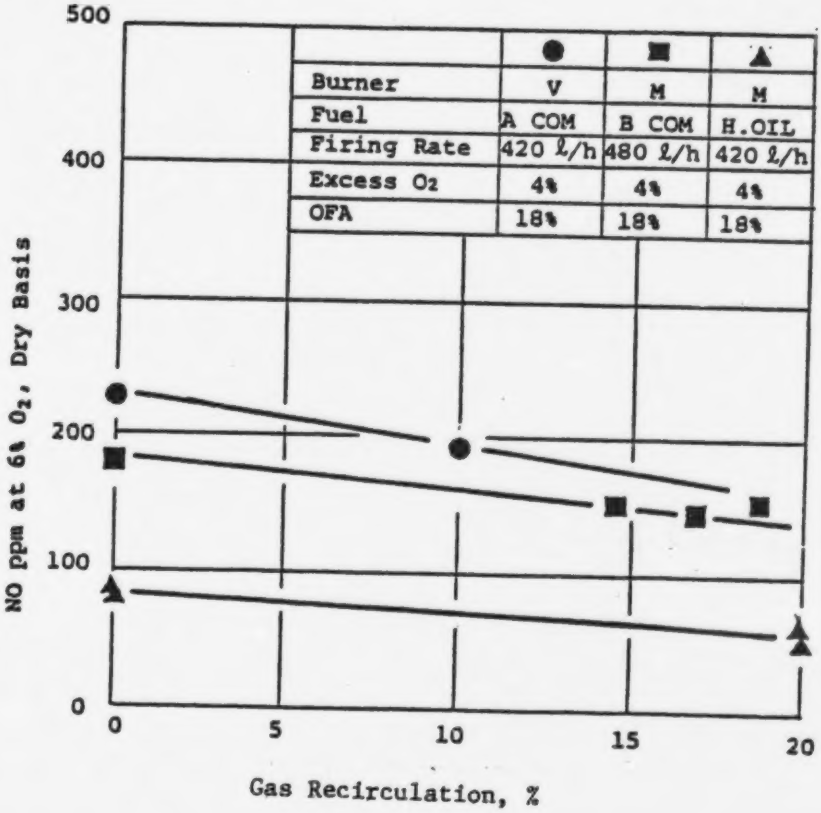
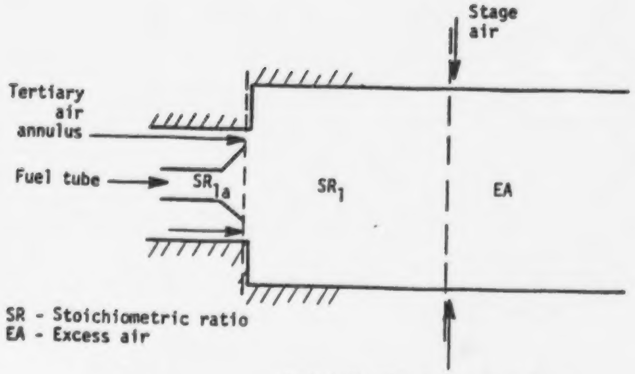


Figure 4.4-7. Combined FGR/staged combustion control of NO_x emissions from COM combustion. (Reference 27).



Modified IFRF burner for low NO_x

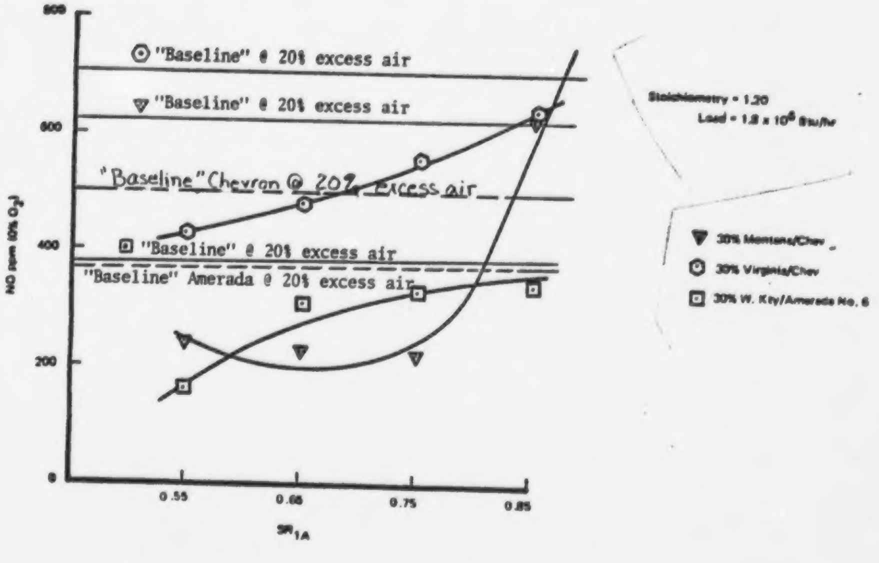


Figure 4.4-8. Low NO_x burner control of NO_x emissions from COM. (Reference 25).

behavior with regard to the stoichiometric ratio in the fuel tube. The two COMs made with higher nitrogen Chevron oil also showed different trends than did the West Kentucky COM made with lower nitrogen oil. These differences indicate the need for a more detailed understanding of the effects of coal and oil properties on NO_x emissions from COM combustion.

However, based on these limited data it appears that low-NO_x burners are the most effective NO_x control technology for COM combustion. Of the four combustion modifications examined for COM combustion, low-NO_x burners appear to be the technique that can most consistently reduce NO_x to oil-only levels or below.

4.4.4.2 Secondary Environmental Impacts

As with the other combustion modification technologies discussed above, the increased CO, unburned hydrocarbons, and smoke emissions associated with incomplete combustion are potential secondary environmental impacts. However, if the low-NO_x burner is properly designed and operated, no such impacts should result.

4.5 TRACE ELEMENT CONTROL

This section examines the trace element control capability of the various particulate matter, SO_2, and NO_x control technologies discussed in the previous sections. The impact of each of the technologies on emissions of Classes 1, 2, 3, and 4 trace elements is evaluated on the basis of actual test data, where they are available, and on the basis of the operational characteristics of the emission control system where test data are not available.

As stated in Chapter 3, trace element emissions are generally associated with the fly ash. Thus, technologies that capture high percentages of particulate emissions (fabric filters, ESPs, and wet scrubbers) and technologies that cool the flue gas (wet scrubbers) will be effective in controlling trace element emissions. Fuel cleaning techniques also have an impact on the trace element concentration in the fuel prior to combustion, and will therefore impact trace element emissions. However, some trace elements such as mercury (Hg) are emitted primarily in the gas phase. Although combustion modifications (such as LEA, staged combustion, FGR or low-NO_x burners) that alter the oxygen concentration or temperature in the flame zone may impact trace element emissions by affecting the oxidation of volatile trace element compounds, there are insufficient data to characterize the effects of combustion modifications on emissions of trace elements. Enrichment characterics may be affected by potential particle size distribution changes associated with combustion modification; but this has not been shown in the data.

No trace element collection efficiency data were available for COM, but the observations made for coal- and oil-firing apply directly to COM trace element control.

4.5.1 Impact of Particulate Controls on Trace Element Emissions

High particulate matter collection efficiencies, especially for fine particulates, is critical to trace element control. As discussed in Chapter 3, those trace elements emitted with the flue gas that condense on the fly ash tend to be enriched on the smaller particles. Fabric filters and electrostatic precipitators have both been demonstrated to achieve high fine particulate collection efficiencies. Tables 4.5-1 and 4.5-2 show measured trace element collection efficiencies for fabric filters and ESPs, respectively. These data show fabric filters to achieve over 99 percent collection of most trace elements except mercury and selenium, two trace elements which tend to remain all or partly in the vapor phase. Table 4.5-2 shows ESPs to achieve greater than 95 percent trace element removal in most cases. As with fabric filters, lower collection efficiencies were observed for Hg and Se.

Comparison of data in Tables 4.5-1 and 4.5-2 shows fabric filters to be slightly more efficient in controlling trace elements. This is to be expected since fabric filters generally achieve a higher degree of fine particulate control than do ESPs.

No test data were available for wet scrubber trace element control when the scrubber was not also being used for SO_2 removal. (Trace element control data for wet FGD systems are presented in Section 4.5.2.) However, venturi scrubbers generally have lower fine particulate collection efficiencies than fabric filters or ESPs. Therefore, scrubbers can be expected to achieve less control of the trace elements that are enriched on small fly ash particles. Wet scrubbers are likely, however, to achieve more control of volatile trace elements such as Hg and Se. The flue gas is cooled to saturation in the scrubber and the gaseous phase trace elements are likely to be condensed.

4.5.2 Impact of SO_2 Controls on Trace Element Emissions

Table 4.5-3 shows measured trace element collection efficiencies for a dual alkali venturi scrubber FGD system. For coal- firing, collection efficiencies ranged from 55 percent for Hg to 99 percent for Cd. The collection efficiencies were significantly lower during oil firing, possibly due to the finer particle size distribution of oil fly ash relative to coal fly ash.

Table 4.5-4 shows limited trace element collection efficiency for a dual alkali FGD system located after an ESP. The scrubber achieved 97 percent removal of Hg. The relatively low removals for Mn and V are due to the collection of most of these elements in the ESP located upstream of the scrubber.

TABLE 4.5-1. TRACE ELEMENT COLLECTION EFFICIENCIES FOR FABRIC FILTERS[31,a]

Element	Collection Efficiency, %	
	Method 5[b]	Impactor[c]
As	99.94	99.94
Be	NR[d]	NR
Cd	NR	NR
Cr[e]	99.70	99.94
Hg[e]	67.14	99.77
Mn	99.94	99.78
Ni[e]	99.51	99.71
Se[e]	93.41	99.40
V	99.95	99.77
Ash	99.63	99.68

[a] This plant is a pulverized coal-fired utility boiler fired with 0.3% S sub-bituminous coal. Samples analyzed by NAA. (Test program sponsored by EPRI.)

[b] Samples collected by EPA Method 5.

[c] Samples collected by low pressure impactor.

[d] NR - Not Reported.

[e] Volatile elements. Method 5 collection efficiencies include volatile fraction collected in impingers. Impactor values do not. Collection of volatile fraction not considered adequate.

TABLE 4.5-2. TRACE ELEMENT COLLECTION EFFICIENCIES FOR ELECTROSTATIC PRECIPITATORS AT COAL-FIRED POWER PLANTS[32]

Trace Element	Collection Efficiency, %				
	Plant A[a]	Plant B[b]	Plant C[c]	Plant D[d,e]	Plant E[d,f]
As	98.4	97.5	NR	99.3	97.0
Be	NR	NR	NR	NR	99.0
Cd	NR	99.6	99.8	63	93
Cr	99.8	98.6	99.8	98.7	97.0
Hg	60.0	42.5	NR	NM	23.0
Mn	94.2	99.1	100	94.4	66.0
Ni	96.3	99.4	99.7	99.8	98.0
Se	97.2	82.8-95.7[g]	94.3	NR	NR
V	95.9	98.8	99.9	99.3	94.0
Ash	99.3	99.5	99.7	99.7	97.5

FOOTNOTES FOR TABLE 4.5-2.

NR = Not Reported; NM = Negative Removal; outlet measured value greater than inlet.

[a] Plant A is a pulverized coal-fired utility boiler fired with low S subbituminous coal. Samples collected by Method 5, analyzed by neutron activation analysis (NAA). (Test program sponsored by EPRI.)

[b] Plant B is a cyclone utility boiler fired with 3.4% S bituminous coal. Samples collected by sampling train similar to EPA Method 5 (multipoint sampling), and analyzed by NAA except Cd by Isotope Dilution Spark Source Mass Spectrometry, Hg by atomic absorption (AA), Ni by X-ray fluorescence; one run for Se by gas chromatography - microwave emission spectroscopy. (Study performed by Oak Rdige National Laboratory.)

[c] Plant C is a utility boiler; boiler and coal type not specified. Samples collected by in stack cascade impactor, analyzed by flameless AA except Se by NAA. (EPA Study.)

[d] Samples collected by SASS train at a single point in the ducts, analyzed by inductively coupled plasma optical emission spectroscopy (ICP) except As by AA and Hg by cold water.

[e] Pulverized coal-fired dry bottom utility boiler fired with Eastern bituminous coal, 3.5-6.3% S.

[f] Pulverized coal-fired dry bottom utility boiler fired with 3.2% S high volatile bituminous coal.

[g] Different values are for 2 different analytical techniques. (Measured both inlet and outlet for these data.)

TABLE 4.5-3. TRACE ELEMENT COLLECTION EFFICIENCY FOR A COMBINED DUAL ALKALI/VENTURI SCRUBBER SYSTEM[33]

Element	Trace Element Collection Efficiency, % Plant L-C[a]	 Plant L-O[a]
As	97	81
Be	98	NM[b]
Cd	99	77
Cr	95	90
Hg	55	87
Mn	98	87
Ni	95	83
Se	97	87
V	98	71
Ash	99.4	75-84

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[a] Industrial boiler capable of firing pulverized coal or No. 6 fuel oil. Plant L-C fired with coal; Plant L-O fired with oil. Samples collected by SASS train, analyzed by ICP except Be by SSMS and Hg by cold vapor.

[b] No meaning - outlet greater than inlet.

TABLE 4.5-4. TRACE ELEMENT COLLECTION EFFICIENCY FOR A DUAL ALKALI SO_2 SCRUBBER PRECEEDED BY AN ESP[33]

Element	Trace Element Collection Efficiency, % Plant D[a]
Hg	97
Mn	60
V	31.2
Ash	18.9

[a] Pulverized coal-fired dry bottom utility boiler fired with Eastern bituminous coal, 3.5-6.3% S. Dual alkali SO_2 scrubber preceeded by ESP. Samples collected by SASS train at a single point in the duct, analyzed by ICP except As by AA and Hg by cold vapor.

TABLE 4.5-5. REDUCTION OF TRACE ELEMENTS IN COAL BY FLOAT-SINK WASHING[34]

	Source A			Source B	
Element	Reduction (%)	Concentration Remaining in coal (ppm)	No. Samples	Reduction (%)	No. Samples
Cd	0-97	0.02-0.10	3	0	1
Cr	28-60	10-20	2	29-56	2
Hg	47	0.17	1	24-47	3
Mn	50-78	7-68	2	50-75	2
Ni	20-27	11-27	2	28-30	2

No trace element collection data were available for other types of wet FGD systems, but their performance should be similar to that of the dual alkali system.

Spray drying and dry injection, two other FGD techniques, will achieve substantial trace element removal since these systems include fabric filters.

Since many trace elements are associated with the ash constituents of the coal used to make COM, they will be removed to some extent by physical coal cleaning. Table 4.5-5 presents removal efficiencies of a few trace elements for "float-sink" coal washing. More extensive data on the effect of physical coal cleaning are presented in Table 4.5-6. Twenty run-of-mine (ROM) coal samples obtained from various geographical locations were subjected to controlled coal cleaning. These removal efficiencies were calculated by comparing the mass of trace element per heating value for the cleaned coal to that for the feed coal. Since the cleaning affects the heating value of the coal, these values more closely reflect the control of trace element emissions from burning the coal than a comparison of the mass of trace elements in the cleaned and feed coals. The average removal efficiencies for all 20 coals are presented in Table 4.5-6, along with the averages for the Eastern, Midwestern, and Western coals. As shown, the Eastern and Midwestern coals were generally cleaned more effectively than the Western coals, possibly because the Western coals have a lower initial concentration of impurities. On the average, As and Mn were removed most effectively (>60 percent) followed by Cd and Cr (>50 percent) and Ni, Se, Hg, and V (>40 percent). Be was removed least effectively (32 percent).

Oil hydrodesulfurization reduces the metals content of the oil and thus achieves some trace element removal. No complete trace element analyses for oil that has been hydrotreated are available, but data on the removal of Ni and V have been reported.[36] Ni and V removal efficiencies of greater than 95 percent have been achieved. For a given catalyst, the percentages of Ni and V removed increase directly with the percentage of sulfur removed from the oil. Since the oil contributes a substantial portion of the Ni and V present in a given COM, oil hydrodesulfurization will have a significant impact on emissions of these trace elements from COM.

TABLE 4.5-6. COMPARISON BY REGION OF REMOVAL EFFICIENCY FOR TRACE ELEMENTS BY PHYSICAL COAL CLEANING[35]

Element	Average, 20 coals	Average, East	Average, Midwest	Average, West
As	62.5	69.2	57.5	49.3
Be	32.4	43.0	28.0	9.87
Cd	51.9	49.5	73.8	44.7
Cr	53.4	65.2	49.8	27.3
Mn	65.1	79.1	72.8	26.7
Hg	41.1	52.2	25.6	24.0
Ni	40.6	49.7	50.7	12.5
Se	40.6	48.2	32.4	27.3
V	45.1	61.6	36.5	10.5
Ash	56	69	55	27

[a] Ash removal efficiency based on mass; trace element removals based on mass per heating value. Negative removal efficiencies were assumed to be zero in calculating averages.

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CHAPTER 5

COST IMPACT OF CONTROL TECHNOLOGIES

This chapter discusses the cost impacts of various PM, SO_2, and NO_x control technologies for boilers firing COM. The cost impacts are evaluated in terms of (1) capital costs, (2) annual operating and maintenance (O&M) costs, (3) annualized costs, and (4) cost effectiveness. The concept of cost effectiveness used in this analysis of various options has been defined by the EPA.[1] Cost effectiveness as used is defined as the annualized cost of a control option divided by the amount of pollutant removed by that option.

The methodology and assumptions used to develop the costs are discussed briefly in Section 5.1. More detail on the emission control costs can be found in Appendix B of this report. Particulate matter control costs are presented in Section 5.2, while Section 5.3 deals with the costs of FGD for combined SO_2 and PM controls. The costs of using low sulfur COM fuels to limit SO_2 emissions are examined in Section 5.4. The annualized cost of alternative techniques for combined SO_2/PM control are compared in Section 5.5. The costs of NO_x control are discussed on a somewhat more qualitative basis than costs for SO_2 and PM control in Section 5.6.

5.1 COSTING METHODOLOGY AND ASSUMPTIONS

5.1.1 Particulate Matter (PM) and SO_2 Control Costs

The cost impacts of various PM and SO_2 control technologies were evaluated for three COM boiler sizes and four COM fuel types. The boiler sizes examined were:

- 8.8 MW (30 x 10^6 Btu/hr),
- 73 MW (250 x 10^6 Btu/hr), and
- 205 MW (700 x 10^6 Btu/hr).

The COM fuel types for which the control technologies were costed are shown in Table 5.1-1. The information in Table 5.1-1 includes coal, oil, and COM composition, and uncontrolled COM emission rates. The fuel compositions were selected from typical coal and oil compositions.[2] Uncontrolled SO_2 and PM emission rates were calculated assuming that (1) all of the fuel sulfur is emitted as SO_2 and (2) 90 percent of the COM ash is emitted as fly ash.[3] Each COM fuel was assumed to be a 50:50 mixture of coal and oil. The "A" fuels in Table 5.1-1 represent low to moderate sulfur COMs, while the "B" fuels represent medium to high sulfur COMs.

TABLE 5.1-1. COM FUEL COMPOSITION AND UNCONTROLLED EMISSIONS

(1) Coal and Oil Compositions[2]

	Coals		No. 6 Oil	
	A) Eastern Low-Ash Low Sulfur	B) Eastern High Ash High Sulfur	1) Low Sulfur	2) High Sulfur
% Sulfur	0.9	3.54	1.03	3.0
% Nitrogen	1.48	1.3	0.3	0.3
% Ash	6.86	10.58	0.1	0.1
Higher heating value kJ/kg (Btu/lb)	32,100 (13,800)	27,500 (11,800)	43,050 (18,500)	43,050 (18,500)

(2) Coal-Oil Mixtures*

	A-1	A-2	B-1	B-2
% Sulfur	0.97	1.95	2.29	3.27
% Nitrogen	0.89	0.89	0.8	0.8
% Ash	3.48	3.48	5.34	5.34
Higher heating value kJ/kg (Btu/lb)	37,600 (16,150)	37,600 (16,150)	35,250 (15,150)	35,250 (15,150)

*Coal-oil mixtures are 50:50 coal and oil. The coal is assumed to be ground to 70% -200 mesh.

(3) Uncontrolled Emissions from COM Fuels**

	COM Fuels			
	A-1	A-2	B-1	B-2
Particulate Emissions ng/J (lb/10^6 Btu)	834 (1.94)	834 (1.94)	1,363 (3.17)	1,363 (3.17)
SO_x Emissions ng/J (lb/10^6 Btu)	559 (1.30)	1,122 (2.61)	1,320 (3.07)	1,883 (4.38)
NO_x Emissions ng/J (lb/10^6 Btu)	258 (0.6)	258 (0.6)	344 (0.8)	344 (0.8)

**Emission factors enable the lb/hr of pollutant generated to be determined by multiplying the fuel thermal input (boiler size in 10^6 Btu/hr) by the emission factor (lb/10^6 Btu).

The costs of PM and SO_2 control technologies presented in this report are based primarily on the technology costs used in the Environmental Protection Agency's (EPA's) Industrial Boiler New Source Performance Standard (NSPS) development.[4] However, two very significant adjustments to those costs have been made for the purposes of this study:

- A retrofit factor was applied to the direct capital cost of the control system. The use of a retrofit factor reflects the fact that emission control systems will likely have to be retrofitted to existing boilers that have been converted to COM-firing.
- Capital and annualized costs were updated from the 1978 dollars used in EPA's study to 1981 dollars.

5.1.1.1 Retrofit factor

A factor of 1.5 was used to adjust the direct capital cost of a PM or SO_2 control system for a new boiler. This factor reflects the expected higher capital costs of retrofit applications. The 1.5 factor was selected based on information presented in a study of FGD costs for EPA's acid rain program.[5] That study recommended a 1.4 utility system retrofit factor when retrofitting was complex. No information was available for industrial retrofit systems.

Considering the boiler sizes chosen for evaluation and the space limitations likely to be found at many existing oil-fired boiler installations, a 1.5 retrofit factor seemed an appropriate estimate. However, the reader should be cautioned that the 1.5 factor is only a rough estimate of the additional costs thay may be incurred in a retrofit situation. The study mentioned above found that factors varied from 0.9 to 3.0 in previous retrofit factor studies. This wide range reflects the fact that retrofit costs are extremely site-specific and indicates the difficulty of selecting a retrofit factor that is applicable to all situations. Only a site-specific evaluation of the factors associated with retrofit, such as space limitations, higher construction costs, and extended construction periods, can accurately quantify the actual retrofit costs.

5.1.1.2 Conversion of \$1978 to \$1981

The cost basis for EPA's Industrial Boiler NSPS Study was mid-1978 dollars. A factor of 1.37, based on the CE Plant Cost Index,[6] was used to update the costs to mid-1981 dollars. The factor was applied to total turnkey costs and to total annaul O&M costs. Although labor and chemical costs may not have increased at the same rate as plant costs, a more detailed breakdown of cost update factors did not seem warranted considering the overall accuracy of the cost estimates.

5.1.1.3 Cost Components

The components of the capital, annual O&M, and annualized costs are shown in Tables 5.1-2 and 5.1-3. More detail on the specific equipment scope, control system design and operating parameters, and unit costs for

TABLE 5.1-2 CAPITAL COST COMPONENTS

(1) Direct Costs

Equipment
+ Installation

= Total Direct Costs

(2) Indirect Costs

Engineering	(10% of direct costs)
+ Construction and Field Expenses	(10% of direct costs)
+ Construction Fees	(10% of direct costs)
+ Start Up Costs	(2% of direct costs)
+ Performance Costs	(1% of direct costs for FGD and PM systems)

= Total Indirect Costs

(3) Contingencies = 20% of (Total Indirect + Total Direct Costs)

(4) Total Turnkey Cost = Total Indirect Cost + Total Direct Cost + Contingencies

(5) Working Capital = 25% of Total Direct Operating Costs

(6) Total Capital Cost = Total Turnkey + Working Capital

TABLE 5.1-3. ANNUAL O&M AND ANNUALIZED COST COMPONENTS

Annual O&M Cost Components

(1) Direct Operating Costs

Direct Labor
+ Supervision
+ Maintenance Labor, Replacement Parts, and Supplies
+ Electricity
+ Water
+ Steam
+ Waste Disposal
  Solids (Fly ash and bottom ash)
  Sludge
  Liquid
+ Chemicals

Total Non-Fuel O&M
+ Fuel

= Total Direct Operating Costs

(2) Indirect Operating Costs (Overhead)

Payroll (30% Direct Labor)
+ Plant (26% of Direct Labor + Supervision + Maintenance Costs)

= Total Indirect Operating Costs

(3) Total Annual Operating and Maintenance Costs = Total Direct + Total Indirect Costs

Annualized Costs

(1) Total Annualized Cost = Annual Operating Costs + Capital Charges

(2) Capital Charges

= Capital recovery + interest on working capital + miscellaneous (G&A, taxes and insurance)

(3) Calculation of Capital-Related Cost Components

A. Capital Recovery = Capital Recovery Factor (CFR) x Total Turnkey Cost

TABLE 5.1-3. (Continued) ANNUAL O&M AND ANNUALIZED COST COMPONENTS

$$\text{CFR} = \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

i = interest rate

n = number of years of useful life of boiler or control system

PM control systems - n = 20
SO_2 control systems - n = 15
NO_x control systems - n = 30

B. Interest on Working Capital = 10% of working capital

C. G&A, taxes and insurance = 4% of total turnkey cost labor, electricity, water, chemicals, and waste disposal can be found in Appendix B.

5.1.1.4 Other Sources of Cost Estimates

The costs for dry injection of nahcolite and the use of low sulfur COM fuels were based on references and information other than that contained in EPA's NSPS cost study. The references used to develop the costs for dry injection and low sulfur COM are given in the sections of this chapter dealing with those technologies.

5.1.2 NO_x Control Costs

The costs of NO_x control through combustion modifications such as low excess air, staged combustion, flue gas recirculation, and low-NO_x burners are extremely boiler-specific. The use of these techniques on some existing boilers may require considerable boiler modification, while their implementation on other boilers may be less costly. Therefore, NO_x control costs are presented in a more qualitative manner than PM or SO_2 control costs. Additional equipment requirements, such as O_2 monitors or additional fan capacity and boiler modifications that might be required in implementing a particular combustion modification technology discussed in Section 5.6.

5.2 PARTICULATE MATTER CONTROL COSTS

This section presents the costs for two PM control devices, ESPs and fabric filters, applied to boilers firing COM. Costs for the ESPs were based on a PM control level of 43 ng/J (0.1 lb/10^6 Btu), while costs for the fabric filter were based on a 21 ng/J (0.05 lb/10^6 Btu) PM control level. These control levels were chosen because they represent what is considered typical performance of the given control devices.[4] Documentation of the assumptions and bases used in developing the PM control costs can be found in Appendix B.

5.2.1 ESP Control Costs

5.2.1.1 Capital Costs

Capital costs for ESPs applied to COM boilers are shown in Figure 5.2-1. Total capital costs range from about $600,000 for a 30 x 10^6 Btu/hr boiler to $4.9 million for a 700 x 10^6 Btu/hr unit firing low sulfur COM. The higher capital costs for "A" COM fuels reflects the fact that COMs are made with a lower sulfur coal.[7] Lower sulfur fuels tend to produce fly ash that is harder to collect with ESP's than fly ash from high sulfur fuels. The costs for the ESPs applied to the boilers firing the low sulfur COM (A fuels; about 1 to 2 percent sulfur COM) are based on an ESP collector area of 200 ft^2/1,000 acfm. Costs for the precipitators applied to "B" COM units (nominal 2.5 to 3.5 percent S COM) are based on an ESP collector area of 175 ft^2/1,000 acfm.

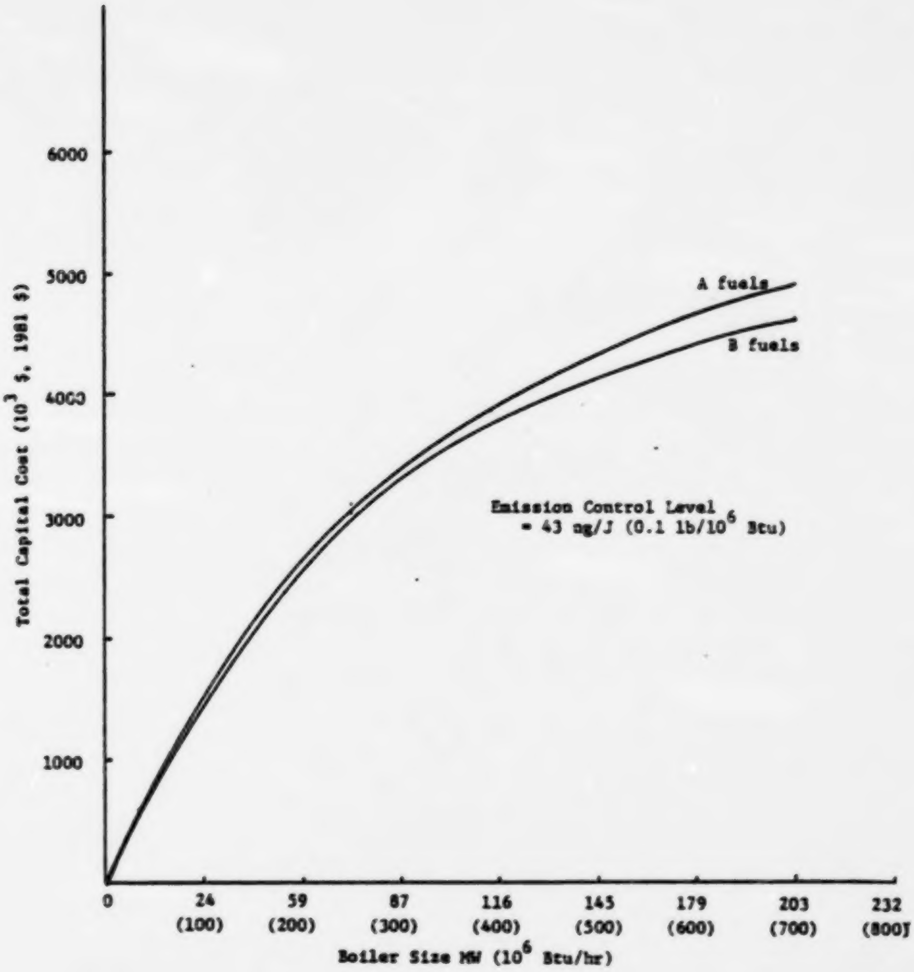


Figure 5.2-1. Capital cost of ESPs applied to COM boilers.

Figure 5.2-1 also reflects the economics of scale in ESP capital costs for larger boiler sizes. It should also be noted that capital costs depend strongly on the retrofit factor for a particular site. As discussed earlier, costs in this study are based on a retrofit factor of 1.5.

5.2.1.2 Annual O&M and Annualized Costs

Figure 5.2-2 shows both annual O&M and annualized costs for ESPs applied to COM units. The annual O&M costs are based on a 60 percent annual capacity factor.

Figure 5.2-2 shows annual O&M costs ranging from about \$50,000/yr for a 30 x 10^6 Btu/hr boiler to about \$310,000 for a 700 x 10^6 Btu/hr boiler. The higher annual O&M costs for the "B" fuels reflects the higher ash content of the "B" COM and the associated increase in ash disposal costs. Annualized costs, which include capital related charges, vary from about \$140,000/yr to \$1.04 million/yr for the range of boiler sizes examined.

Figure 5.2-3 presents the annualized costs of the ESP normalized to a boiler heat input basis. The cost impact of the ESP decreases with increasing boiler size on a normalized basis, ranging from about \$0.90/10^6 Btu to \$0.30/10^6 Btu for the boiler sizes examined.

5.2.1.3 Cost Effectiveness

The cost effectiveness of a control technology is defined and used throughout this report as the cost per ton of pollutant removed. The cost per ton of PM removed is shown in Figure 5.2-4 for three boiler sizes: 30, 250, and 700 x 10^6 Btu/hr. Two trends are evident in this figure: (1) ESPs have a lower cost per ton of particulate removed as boiler size increases and (2) for a given boiler size, the cost per ton of particulate removal is lower for higher ash COM fuels. For the "A" fuels, the cost per ton of PM removed with an ESP varies from about \$970 to \$310 for the 30 x 10^6 Btu/hr and 700 x 10^6 Btu/hr sizes, respectively. The cost per ton for the higher ash "B" fuels ranges from about \$560 to \$185 for the same boiler sizes, about 40 percent less per ton than for the A fuels.

The cost effectiveness values presented in Figure 5.2-4 are based on a 60 percent annual capacity factor. The cost effectiveness would be improved at higher boiler capacity factors.

5.2.2 Fabric Filter Control Costs

5.2.2.1 Capital Costs

Figure 5.2-5 shows the capital costs of fabric filters applied to COM-fired boilers as a function of boiler size. The capital cost for fabric filters depends primarily on the flue gas flow rate, and is not a function of COM fuel properties. Thus, the capital costs are approximately the same for both the "A" and "B" fuels. Figure 5.2-5 shows total capital costs ranging from \$400,000 for a 30 x 10^6 Btu/hr boiler to \$6.04 million for a 700 x 10^6 Btu/hr boiler. Comparison of these costs with those presented in

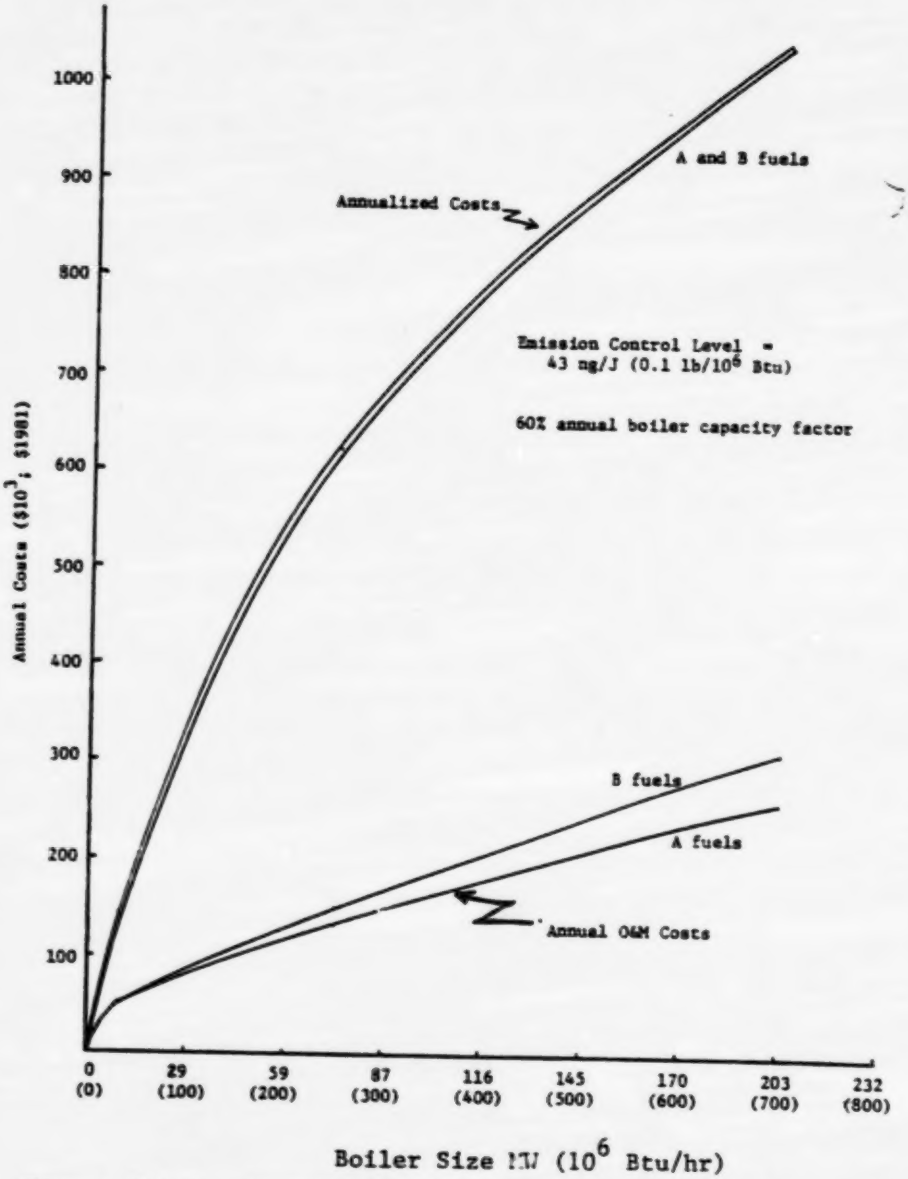
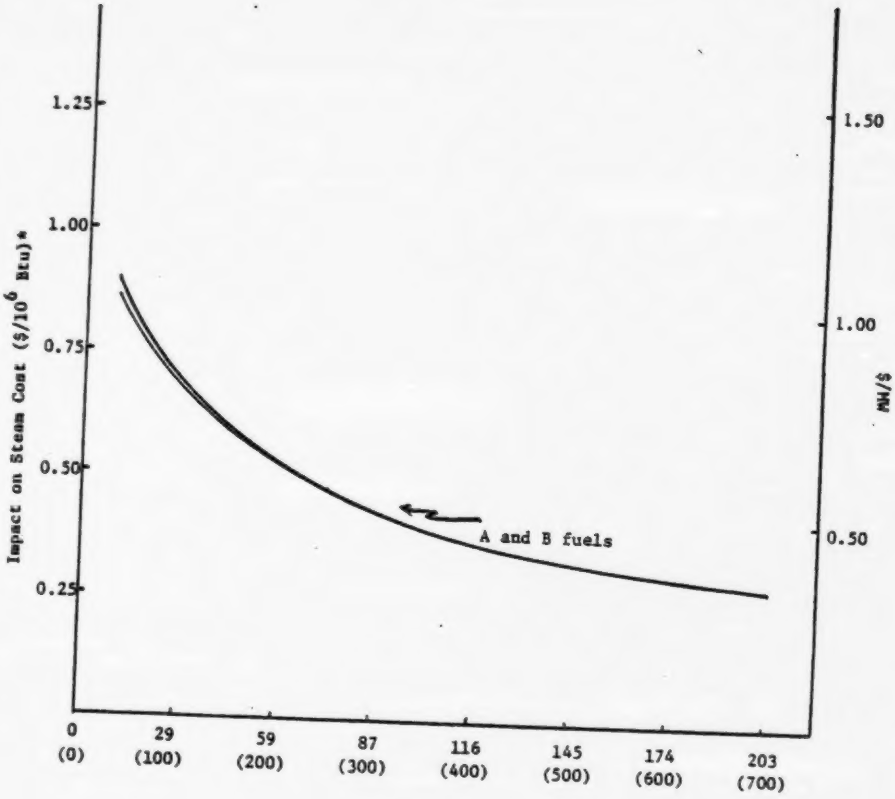


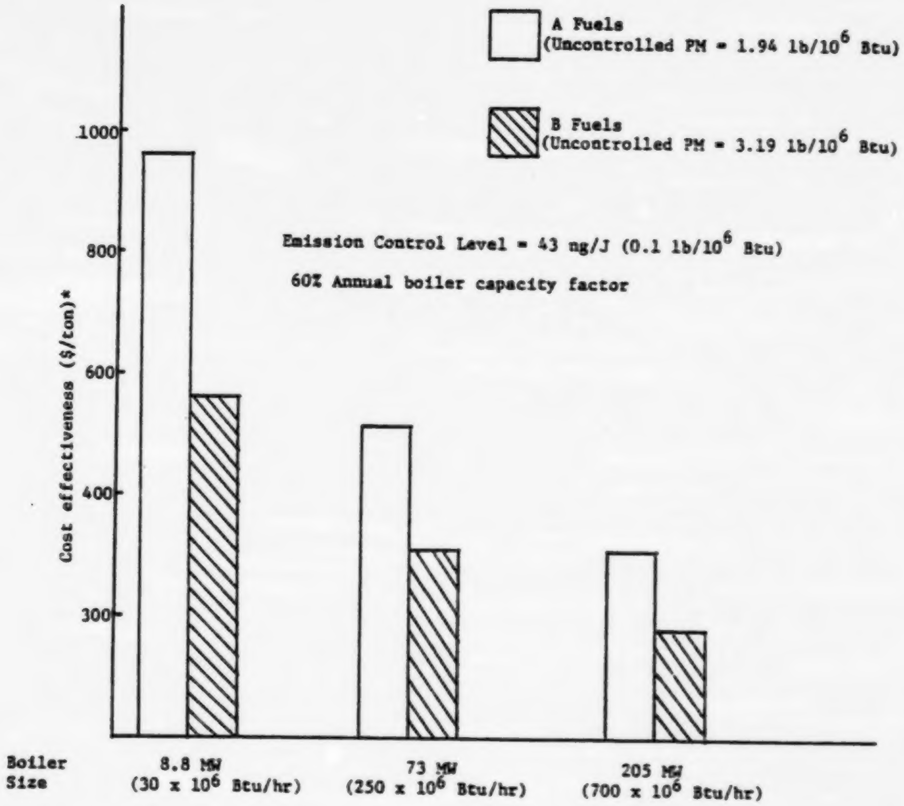
Figure 5.2-2. Annual O&M and annualized costs of ESPs applied to COM boilers.



Boiler Size MW (10^6 Btu/hr)

Figure 5.2-3. Impact of ESP on steam costs for COM boilers.

*Heat input, 60% annual boiler capacity factor.



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* Divide by 0.908 to convert to $/Mg

Figure 5.2-4. Cost effectiveness of ESPs on COM boiler.

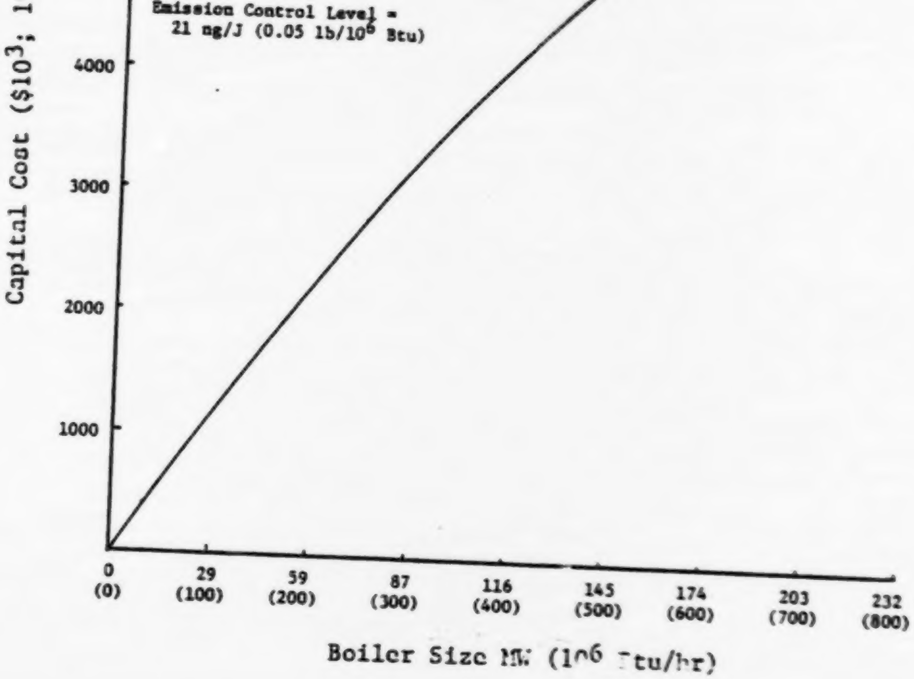


Figure 5.2-5. Capital costs of fabric filters applied to COM boilers.

Section 5.2.1 for ESPs indicates that fabric filters are less expensive for boiler sizes up to about 300 x 10^6 Btu/hr, but become more expensive than ESPs for larger boilers. However, such a comparison should only be made with the following points in mind:

(1) The ESP costs are based on a 0.1 lb/10^6 Btu control level; ESP capital costs can increase significantly for lower controlled emission levels. Fabric filter costs, however, are not strongly dependent on the desired controlled PM emission rate.

(2) The capital cost of the ESP can increase significantly if the fly ash has a high resistivity. Fabric filter costs, which do not depend on ash resistivity, may be lower than ESP costs in high resistivity ash applications.

5.2.2.2 Annual O&M and Annualized Costs

Annual O&M and annualized costs for fabric filters applied to COM-fired boilers are shown in Figure 5.2-6. As with the ESPs, annual O&M costs for "B" COM fuels are slightly higher than for "A" fuels; the difference is due to the increased waste disposal costs for the higher ash COMs. Annual O&M costs for fabric filters range from about $55,000/yr to $522,000/yr for the boiler sizes examined. Annualized costs range from about $120,000/yr for a 30 x 10^6 Btu/hr boiler to $1.47 million for a 700 x 10^6 Btu/hr unit.

Figure 5.2-7 shows the annualized costs for fabric filters normalized to a heat input basis. The cost impact of fabric filters ranges from $0.75/$10^6$ Btu for a 30 x 10^6 Btu/hr unit to about $0.40/$10^6$ Btu for a 700 x 10^6 Btu/hr boiler. (Comparable ESP costs ranged from $0.90/$10^6$ Btu to $0.30/$10^6$ Btu).

5.2.2.3 Cost Effectiveness

The cost per ton of PM removed with fabric filters is shown in Figure 5.2-8. The same expected trends as observed for ESP cost effectiveness are also evident for fabric filters. For the lower ash "A" COM fuels, the cost per ton of PM removed ranges from about $790 to $410 for the 30 x 10^6 Btu/hr and 700 x 10^6 Btu/hr units, respectively. Fabric filter cost per ton of PM removal is decreased for the higher ash "B" COM fuels, ranging from about $490/ton to $260/ton for the boiler sizes examined. These cost effectiveness values are similar to those presented earlier for ESPs (Section 5.2.1.3).

5.3 COMBINED SO_2/PM CONTROL WITH FGD SYSTEMS

This section presents the costs for three FGD technologies capable of controlling both SO_2 and PM emissions from COM combustion. The technologies evaluated are:

- double alkali wet FGD,

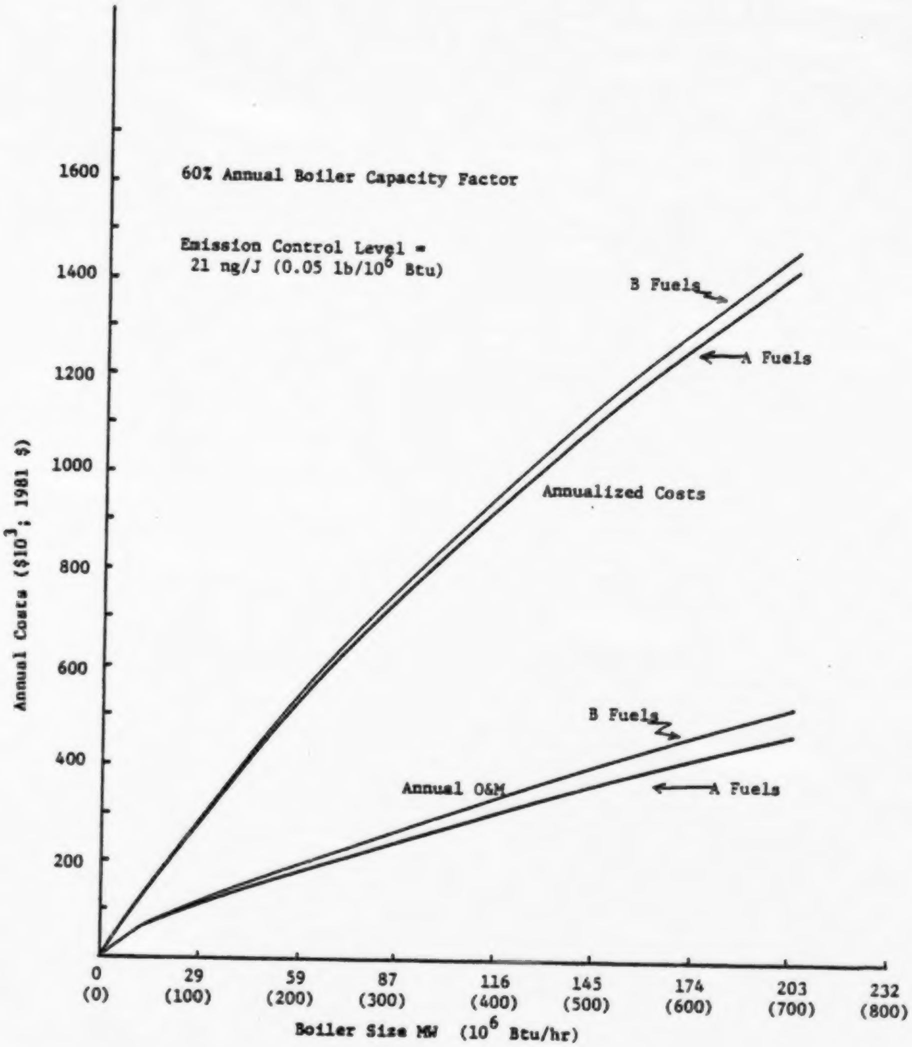


Figure 5.2-6. Annual O&M and annualized costs for fabric filter applied to COM boilers.

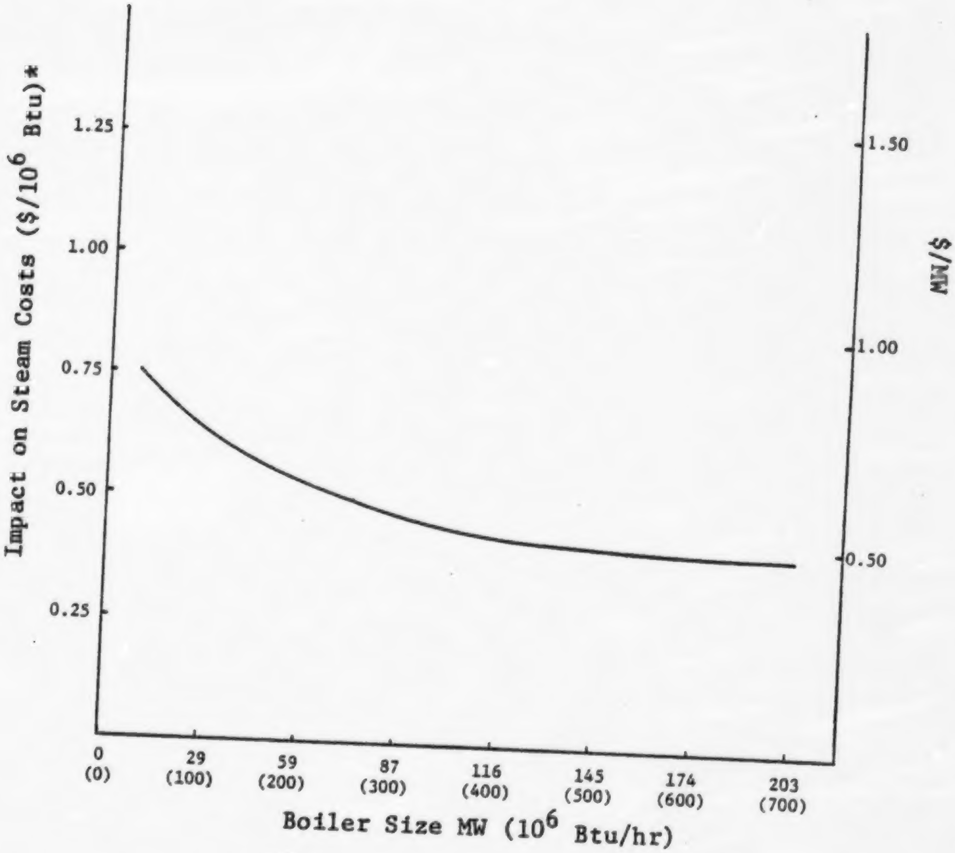
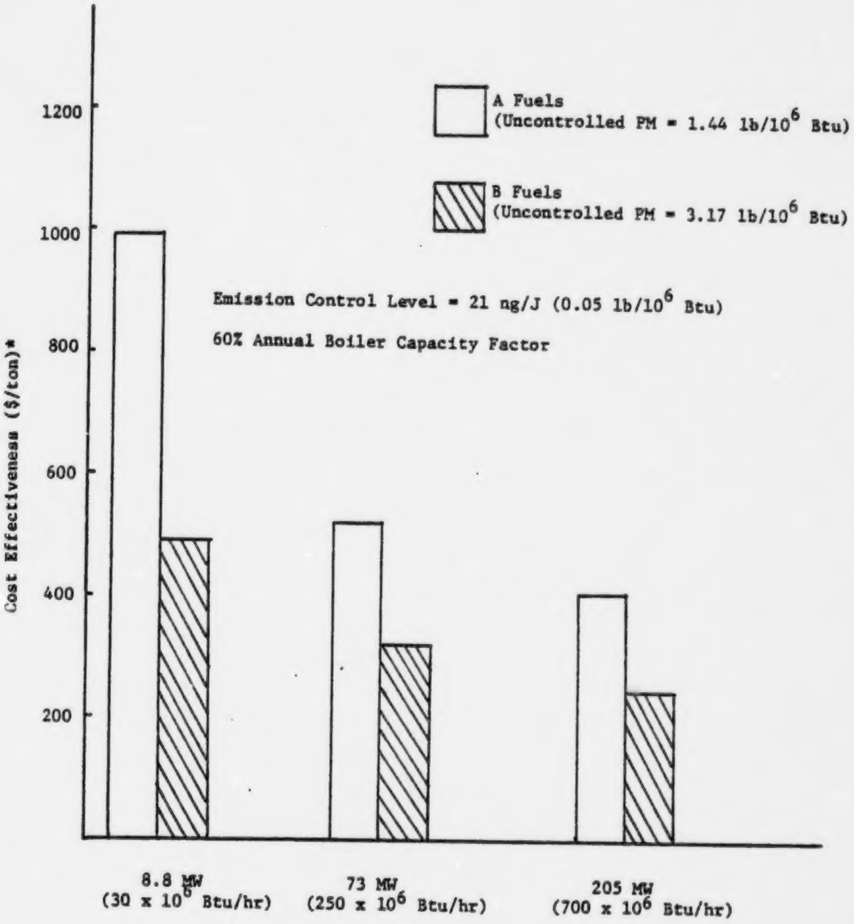


Figure 5.2-7. Impact of fabric filter on steam costs for COM boilers.

*Heat input basis; 60% annual boiler capacity factor.



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* Divide by 0.908 to convert to $/Mg.

Figure 5.2-8. Cost effectiveness of fabric filters for COM boilers.

- lime spray drying, and
- dry injection of nahcolite.

Costs for both the spray drying and dry injection FGD systems include the costs for a fabric filter. The fabric filter is required for collection of fly ash and the dry waste solids produced by desulfurization. Costs for the double alkali wet FGD system are based on a venturi-type scrubber and include costs for a mechanical collector located upstream of the scrubber. The mechanical collector is assumed to capture 80 percent of the fly ash leaving the boiler before the flue gas enters the scrubber. Although lime and limestone wet FGD costs were not specifically evaluated in this report, they are expected to be very similar to double alkali FGD system costs.[8]

There are several assumptions and bases used in developing the wet and dry FGD system costs that are important to interpretation of the cost data presented in this section. The most important assumptions and bases are highlighted in Table 5.3-1.

To adequately evaluate FGD system costs as many as three levels of SO_2 removal were examined for each FGD system type and COM fuel sulfur content. The matrix of SO_2 removal levels, COM fuel types, and resulting SO_2 emission levels examined for wet FGD systems is shown in Table 5.3-2. The number and type of cases examined for lime spray drying and dry injection were scaled back somewhat from the cases used to examine wet FGD costs. However, the dry FGD cases examined still provide a wide range of cost data (Table 5.3-3). The number of dry FGD cases examined is limited relative to the number of wet FGD cases due primarily to a lack of full-scale process data useful for costing dry FGD at high SO_2 removal (90 percent) on higher sulfur fuels (3 percent S or greater).

Capital, annual O&M, and annualized costs for each of the three FGD processes are presented in the following sections. Cost effectiveness and steam cost data are also presented. Section 5.3.4 compares the costs of the three technologies as a function of boiler size and COM sulfur content.

5.3.1 Wet FGD System Costs

5.3.1.1 Capital Costs

Capital costs for double alkali wet FGD systems are shown in Figures 5.3-1 and 5.3-2. Figure 5.3-1 shows capital costs as a function of boiler size for two "low" sulur COMs: A-1 (0.97 percent sulfur) and A-2 (1.95 percent sulfur).

In general, Figures 5.3-1 and 5.3-2 show wet FGD system total retrofitted capital costs to range between \$1.25 to \$1.8 million for a 30 x 10^6 Btu/hr boiler and \$7.3 to \$8.4 million for a 700 x 10^6 Btu/hr boiler. The capital costs for a specific application will, of course, be a

TABLE 5.3-1. IMPORTANT ASSUMPTIONS AND BASES USED TO DEVELOP FGD SYSTEM COSTS

General

- Capital costs for FGD systems are based on a retrofit factor of 1.5 (used to adjust the direct capital costs).
- Labor costs are based on 1 full-time operator and ½-time supervisor.
- Waste sludge and solids are assumed to be disposed of off-site at a rate of $15/ton [$0.0166/kg] ($1978).
- All costs are based on scrubbing 100% of the flue gas (no partial scrubbing).

Wet FGD Systems

- Capital costs are based on shop-fabricated equipment; single scrubber for 8.8 and 73 MW units; 3 scrubbers for 205 MW units.
- Stack gas reheat is not included in capital or annual costs.
- Reagent costs ($ 1978):

  Sodium carbonate: $0.099/kg ($90/ton)

  Lime: $0.039/kg ($35/ton)

Spray Dryer Systems

- Capital costs are based on single shop-fabricated spray dryer for all boiler sizes examined.
- Reagent costs ($ 1978):

  Lime: $0.039/kg ($35/ton)

Dry Injection Systems[a]

- Capital costs are scaled-down from large utility system theoretical study. (High degree of uncertainty.)
- Reagent costs ($ 1978),[also quite uncertain]:

  Nahcolite: $0.042/kg ($38/ton)

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[a] For further discussion of the relative certainty of the dry injection costs, see Section 5.3.3.

TABLE 5.3-2. SO_2 CONTROL LEVELS AND COM FUELS EVALUATED FOR WET FGD SYSTEMS

COM Fuel	Sulfur Content (%)	Uncontrolled SO_2 Emissions ng/J (lb/10^6 Btu)	SO_2 Control Levels Examined	
			SO_2 Removal (%)	Controlled SO_2 Emissions ng/J (lb/10^6 Btu)
A-1	0.97	559 (1.30)	50	280 (0.65)
			70	168 (0.39)
A-2	1.95	1,122 (2.61)	50	559 (1.30)
			70	335 (0.78)
			90	112 (0.26)
B-1	2.3	1,320 (3.07)	50	662 (1.54)
			70	396 (0.92)
			90	132 (0.31)
B-2	3.3	1,883 (4.38)	70	563 (1.31)
			90	188 (0.44)

TABLE 5.3-3. SO_2 CONTROL LEVELS AND COM FUELS EVALUATED

COM Fuel	Sulfur Content (%)	Uncontrolled SO_2 Emissions ng/J ($lb/10^6$ Btu)	SO_2 Control Levels Examined	
			SO_2 Removal (%)	Controlled SO_2 Emissions ng/J ($lb/10^6$ Btu)
Lime Spray Drying				
A-1	0.97	559 (1.30)	70	168 (0.39)
A-2	1.95	1,122 (2.61)	70	335 (0.78)
			90	112 (0.26)
B-1	2.3	1,320 (3.07)	70	396 (0.92)
			90	132 (0.31)
B-2	3.3	1,883 (4.38)	70	188 (0.44)
Dry Injection of Nahcolite				
A-1	0.97	559 (1.30)	70	168 (0.39)
B-2	3.3	1,883 (4.38)	70	188 (0.44)

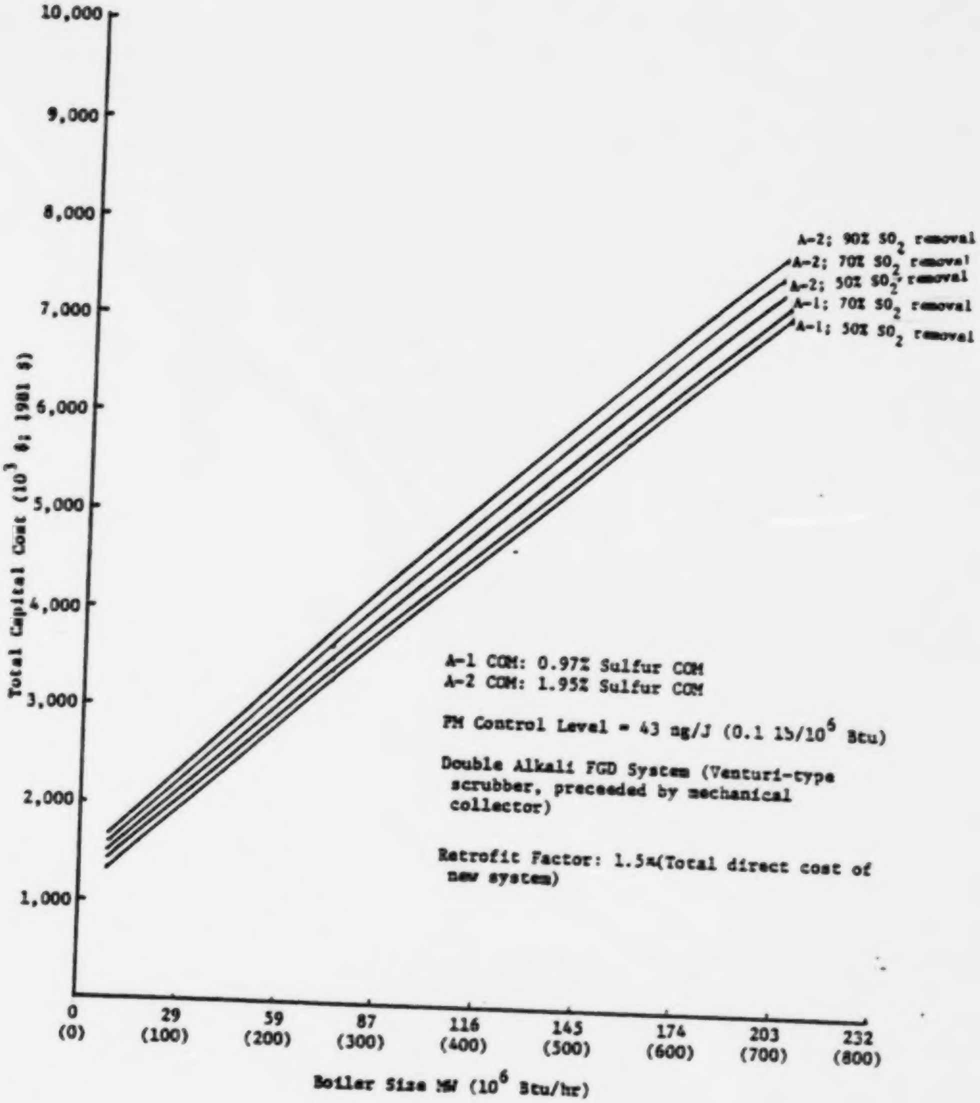


Figure 5.3-1. Total capital costs for wet FGD (combined SO_2/PM removal) - Low sulfur COMs.

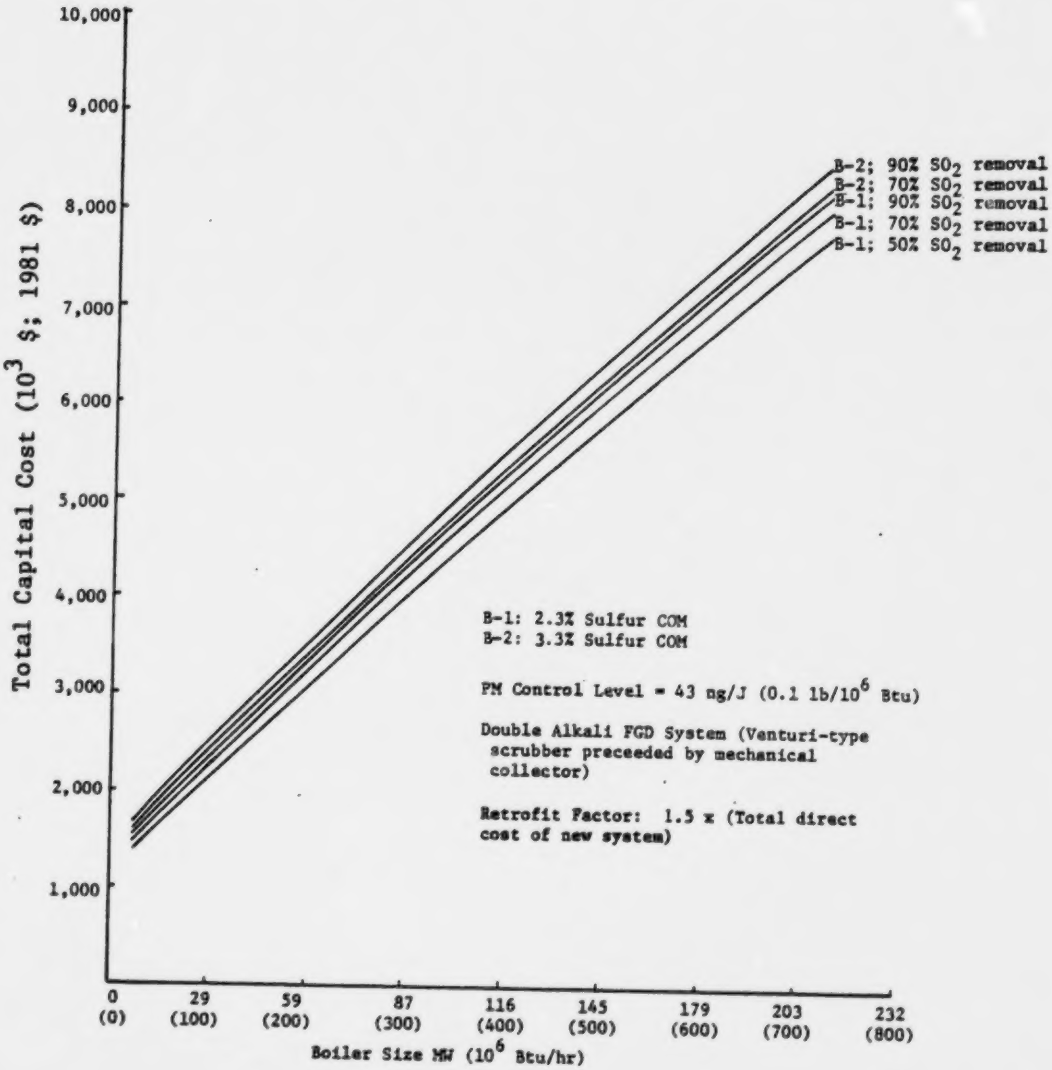


Figure 5.3-2. Total capital costs for wet FGD (combined SO_2/PM removal) medium-high sulfur COM.

function of COM sulfur content, required SO_2 removal, boiler size, and retrofit difficulty.

The cost data in Figure 5.3-1 indicate a 5 to 10 percent difference in wet FGD system capital costs between the two sulfur levels in the fuel (at an SO_2 removal level of 70 percent). Figure 5.3-1 also shows the variation of wet FGD system capital costs as a function of SO_2 removal. For example, the difference in capital costs between 50 and 90 percent SO_2 removal for COM fuel A-2 is about 14 percent for a 700 x 10^6 Btu/hr boiler. The lowest FGD system capital costs are observed for a lower sulfur COM and lower percent SO_2 removal, since the size of the reagent and sludge handling systems is reduced as the amount of SO_2 removed decreases.

Similar trends are observed in Figure 5.3-2. This figure presents capital costs for wet FGD system applied to boilers firing higher sulfur COMs (2.3 to 3.3 percent sulfur). The highest capital costs are associated with the 90 percent SO_2 removal system applied to boilers firing the 3.3 percent sulfur COM. The costs for this system is 4 to 6 percent higher than the 90 percent SO_2 removal system treating flue gas from the lower sulfur "B-1" COM fuel.

5.3.1.2 Annual O&M and Annualized Costs

Figures 5.3-3 and 5.3-4 show the annual O&M and annualized costs for wet FGD systems as a function of boiler size, COM sulfur content, and SO_2 removal. The annual O&M and annualized costs are based on a boiler capacity factor of 60 percent.

The annual O&M costs of a double alkali FGD system applied to lower sulfur COM units (Figure 5.3-3) range between \$330,000 to \$355,000 for a 30 x 10^6 Btu/hr unit and \$940,000 to \$1.32 million for a 700 x 10^6 Btu/hr boiler. Annual O&M costs for double alkali system applied to higher sulfur COM (Figure 5.3-4) are slightly greater, ranging from \$350,000 to \$380,000 for a 30 x 10^6 Btu/hr unit to \$1.21 to \$1.79 million for a 700 x 10^6 Btu/hr boiler. Figures 5.3-3 and 5.3-4 show that, as expected, annual O&M costs increase with increases in the following: boiler size, COM sulfur content, and percent SO_2 removal. The major O&M expenditures for wet FGD are associated with reagent and power consumption, maintenance, and waste disposal.

It should be noted that annual O&M costs for specific applications may differ somewhat from those shown here due to site-to-site variations in hourly labor and reagent costs, boiler capacity factor, FGD system reliability (maintenance costs), and waste disposal practices.

Annualized costs for double alkali wet FGD systems are also shown in Figures 5.3-3 and 5.3-4. These costs vary between \$550,000 to \$680,000 for a 30 x 10^6 Btu/hr boiler and \$2.15 to \$3.2 million for a 700 x 10^6 Btu/hr unit for the range of COM fuels examined.

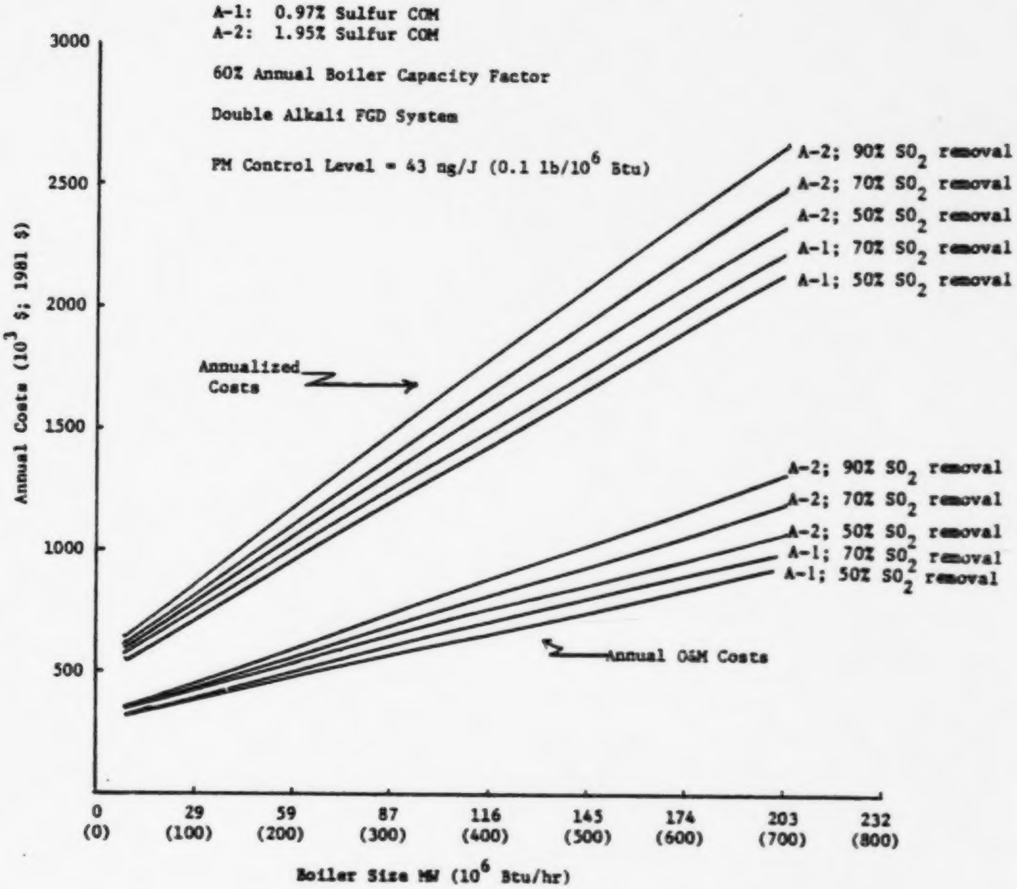


Figure 5.3-3. Annual O&M and annualized costs of wet FGD (combined SO_2/PM removal)-low sulfur COM.

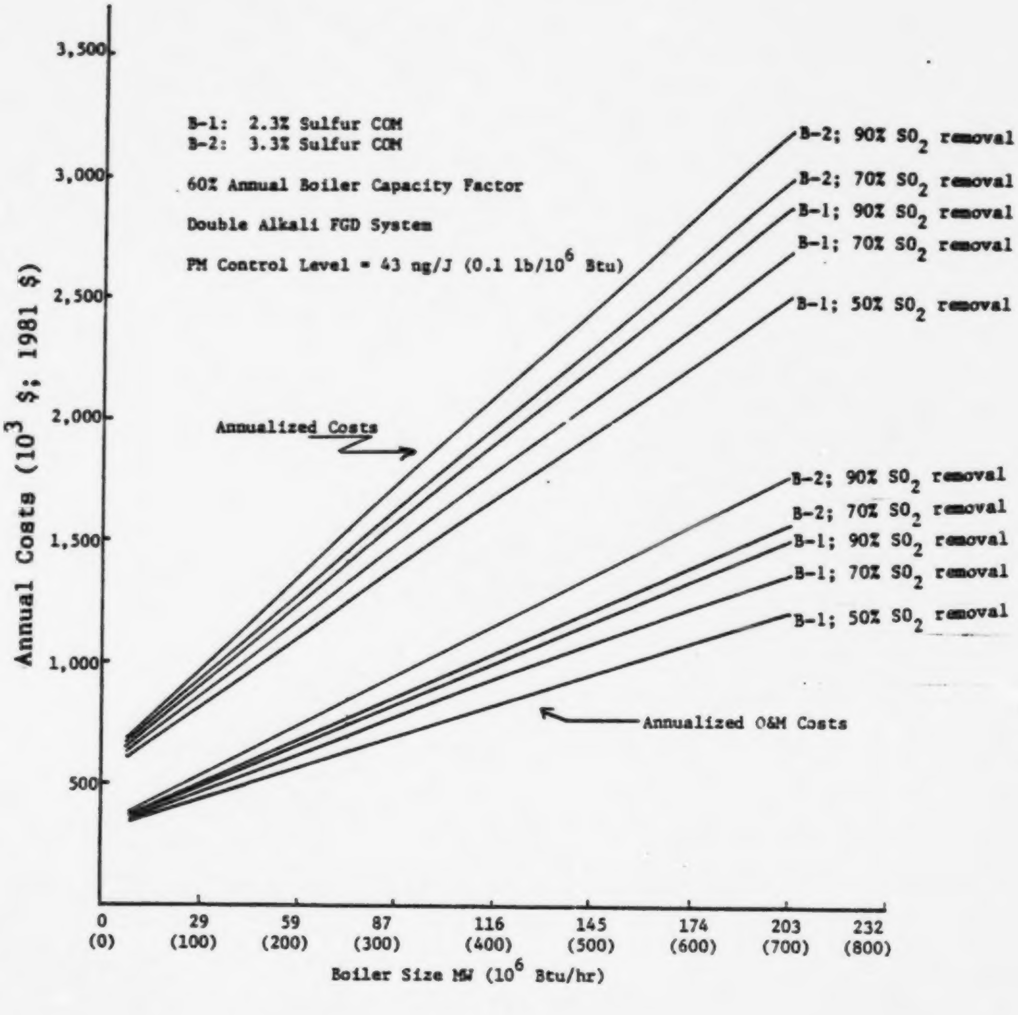


Figure 5.3-4. Annual O&M and annualized costs for wet FGD (combined SO_2/PM removal) - high sulfur COM.

Figure 5.3-5 shows the range of normalized annaulized costs for the boiler sizes, COM sulfur contents, and SO_2 removals examined. The cases ranged from 50 percent SO_2 removal on a low sulfur COM (A-1) to 90 percent SO_2 removal on a high sulfur COM (B-2). For the low sulfur, low removal case, normalized annual costs range from $3.53/$10^6$ Btu to $0.58/$10^6$ Btu (heat input basis) for the boiler sizes examined. Normalized costs for the high sulfur, high removal case range from $4.33/$10^6$ Btu to $0.87/$10^6$ Btu. The latter costs are 22 to 50 percent greater than those for the low sulfur, low removal cases, with the percent difference increasing as boiler size increases.

Normalized annualized costs for the other cases shown in Figures 5.3-3 and 5.3-4 would fall between the two cases shown in Figure 5.3-5.

5.3.1.3 Cost Effectiveness

Figure 5.3-6 shows the cost per ton of SO_2 removed with wet FGD as a function of boiler size, COM sulfur content and percent SO_2 removal. Because the FGD systems evaluated here were designed to remove PM as well as SO_2, the values for the cost per ton of SO_2 removed shown in Figure 5.3-6 are slightly higher than if the FGD system only removed SO_2. [Using the FGD system for PM removal leads to higher system costs because of increased waste disposal requirements (fly ash) and the added capital cost of the mechanical collector.] However, the bulk of the FGD system costs are attributable to SO_2 removal and the trends and relative cost effectiveness values remain valid and useful. Three trends are obvious from Figure 5.3-6:

- Cost per ton of SO_2 removed decreases dramatically as boiler size increases.

- The cost per ton of SO_2 removed decreases as the overall SO_2 removal increases (for the range of removals evaluated). That is, for a given fuel and boiler size, 90 percent SO_2 removal costs less on a per ton of SO_2 removed than 70 percent SO_2 removal.

- The cost per ton of SO_2 removed decreases as the COM sulfur content increases. (That is, for a given SO_2 removal and boiler size, the cost per ton of SO_2 removed will be lower for higher sulfur fuels.)

The highest cost per ton of SO_2 removed in the cases examined was for the 30 x 10^6 Btu/hr boiler firing low sulfur (0.97 percent S) COM with 50 percent SO_2 removal. In this case, the cost exceeded $10,000/ton of SO_2 removed. At the other end of the range, the cost per ton of SO_2 removed from a 700 x 10^6 Btu/hr boiler firing high sulfur COM (3.3 percent S) was $443 at an SO_2 removal level of 90 percent. These data and the other cases presented in Figure 5.3-6 show the strong sensitivity of cost effectiveness to COM sulfur content, boiler size, and overall SO_2 removal.

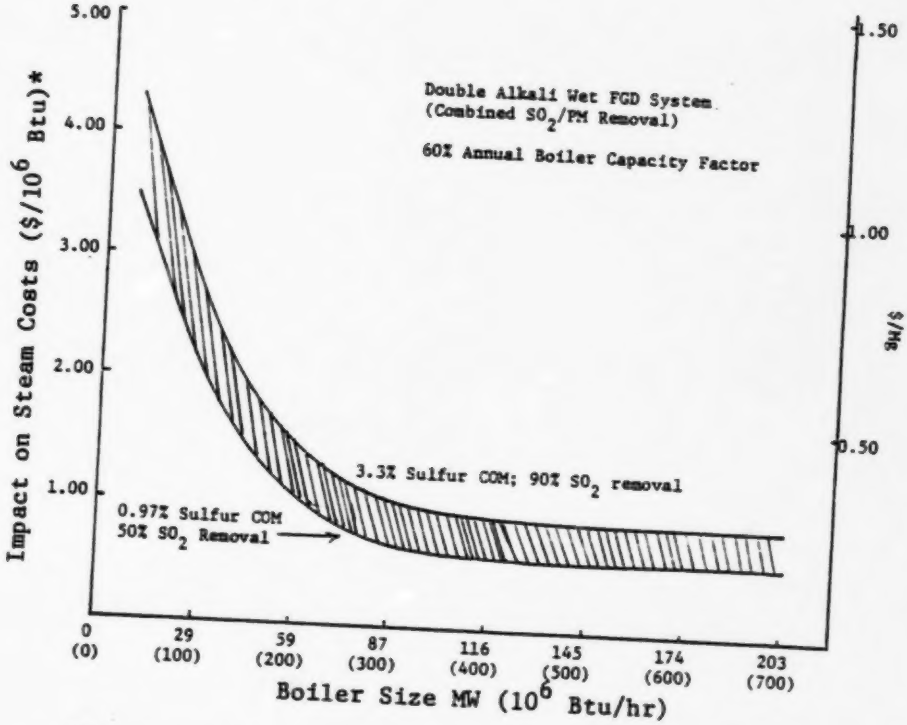


Figure 5.3-5. Range of impact of wet FGD system on steam costs as a function of boiler size.

* Heat input basis.

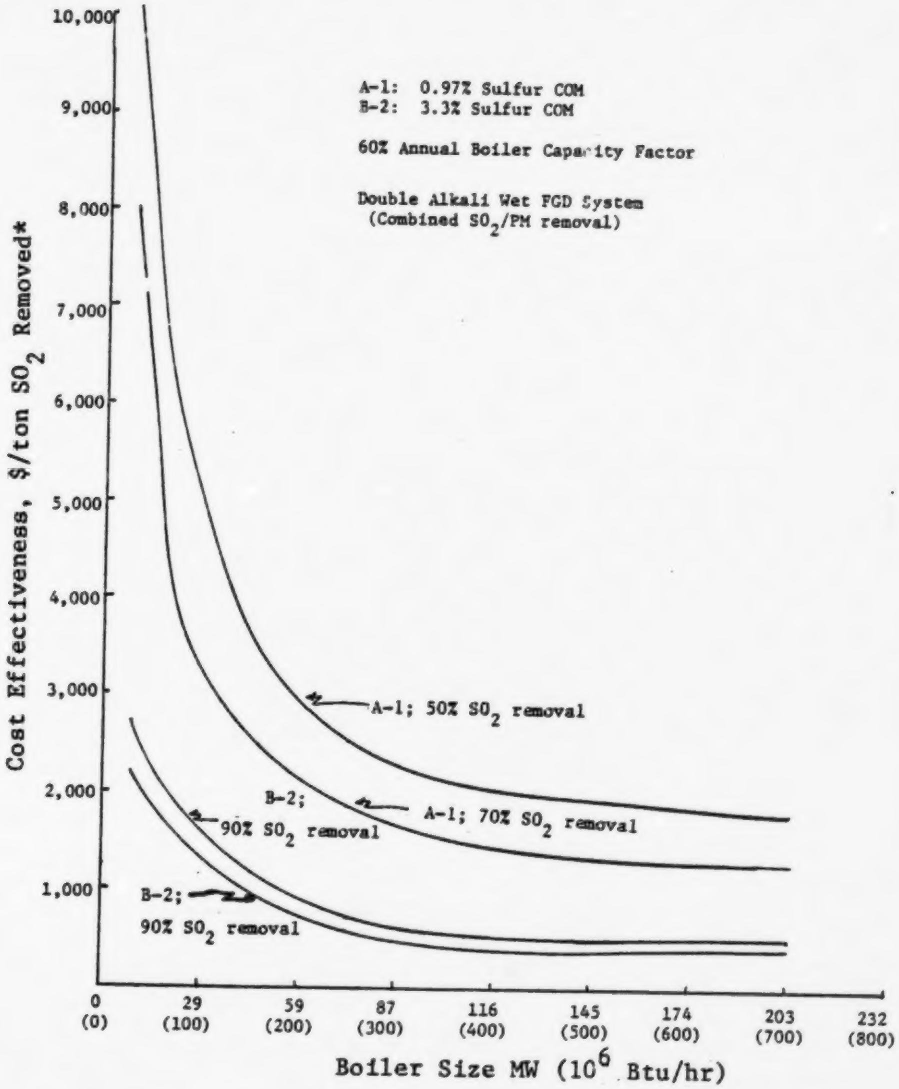


Figure 5.3-6. Cost effectiveness of wet FGD systems.

*Divide by 0.908 to convert to \$/Mg.

5.3.2 Lime Spray Dryer System Costs

5.3.2.1 Capital Costs

Figures 5.3-7 and 5.3-8 show the total retrofitted capital costs for lime spray dryer FGD systems as a function of boiler size, COM sulfur content and percent SO_2 removal. Figure 5.3-7 shows costs for lower sulfur COMs [fuel A-1 = 0.97 percent S; fuel A-2 = 1.95 percent S], while Figure 5.3-8 shows costs for higher sulfur COMs. The spray dryer system costs include the costs of a fabric filter. The fabric filter is used to capture the spray-dried solids as well as fly ash. The retrofit factor of 1.5 was applied to the direct capital costs of the spray drying process equipment and to the costs of the fabric filter. As stated earlier, retrofit factors may vary significantly from site to site.

The retrofitted capital costs for spray dryer FGD systems applied to lower sulfur COM fuels (Figure 5.3-7) range from about $1.2 million for a 30×10^6 Btu/hr boiler to between $10.4 and $10.8 million for a 700×10^6 Btu/hr unit. Similar costs for the higher sulfur COM fuels (Figure 5.3-8) range from $1.2 million to $10.9 million. Spray dryer system capital costs do not vary significantly with the amount of SO_2 removed. Since the sludge handling equipment used in wet FGD systems is not required, only the size of the reagent and solids handling equipment in the spray dryer system is affected by changes in the amount of SO_2 removed. Therefore, because the cost of the reagent and solids handling equipment is small relative to the cost of the spray dryer and the fabric filter, overall capital costs are not significantly dependent on the amount of SO_2 removed.

5.3.2.2 Annual O&M and Annualized Costs

Annual O&M and annualized costs for spray dryer FGD systems are shown in Figures 5.3-9 and 5.3-10. These figures show the relatively strong sensitivity of the annual O&M costs to COM sulfur content and the percent SO_2 removal. The amount of lime per unit of inlet SO_2 required to achieve a given SO_2 removal (stoichiometric ratio) generally increases (1) as the inlet SO_2 to the spray dryer increases and (2) as the desired removal efficiency increases. The effect of the increased operating stoichiometric ratio of lime to inlet SO_2 for high SO_2 removals can be seen in Figure 5.3-10. The annual O&M costs, of which lime and waste disposal costs are major components, are slightly higher for 90 percent SO_2 removal on the "B-1" COM fuel than for 70 percent removal on the higher sulfur "B-2" COM fuel. Not suprisingly, the impact of increased reagent and waste disposal costs is more significant for the larger boiler sizes. Figures 5.3-9 and 5.3-10 show annual O&M costs ranging from about $350,000 for a 30×10^6 Btu/hr boiler to between $834,000 and $1.5 million for a 700×10^6 Btu/hr boiler. As with wet FGD systems, annual O&M costs for specific applications may vary substantially from those shown here due to site-specific labor, maintenance, and chemical costs and/or waste disposal methods.

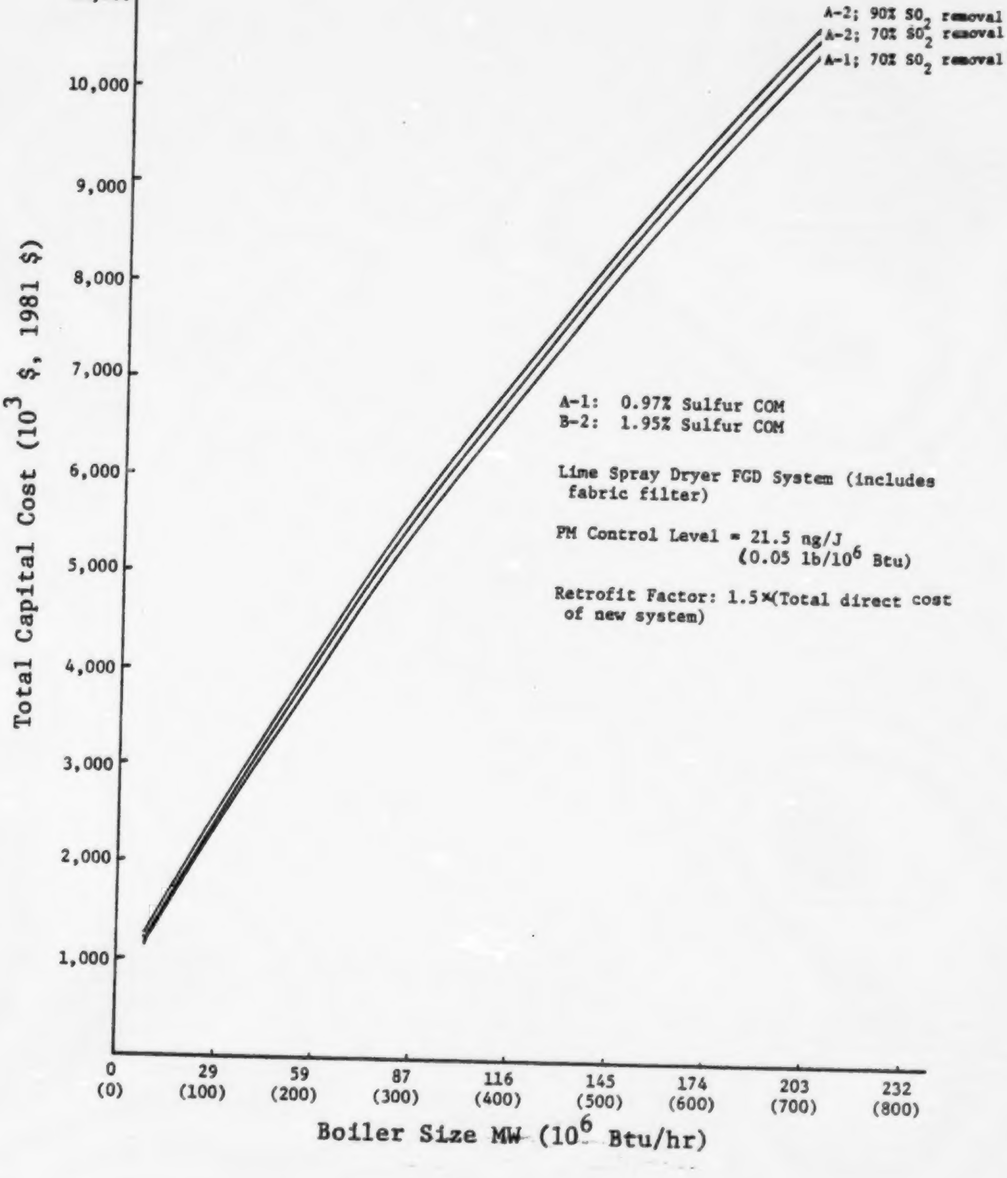


Figure 5.3-7. Total capital costs for spray dryer FGD applied to low sulfur COM.

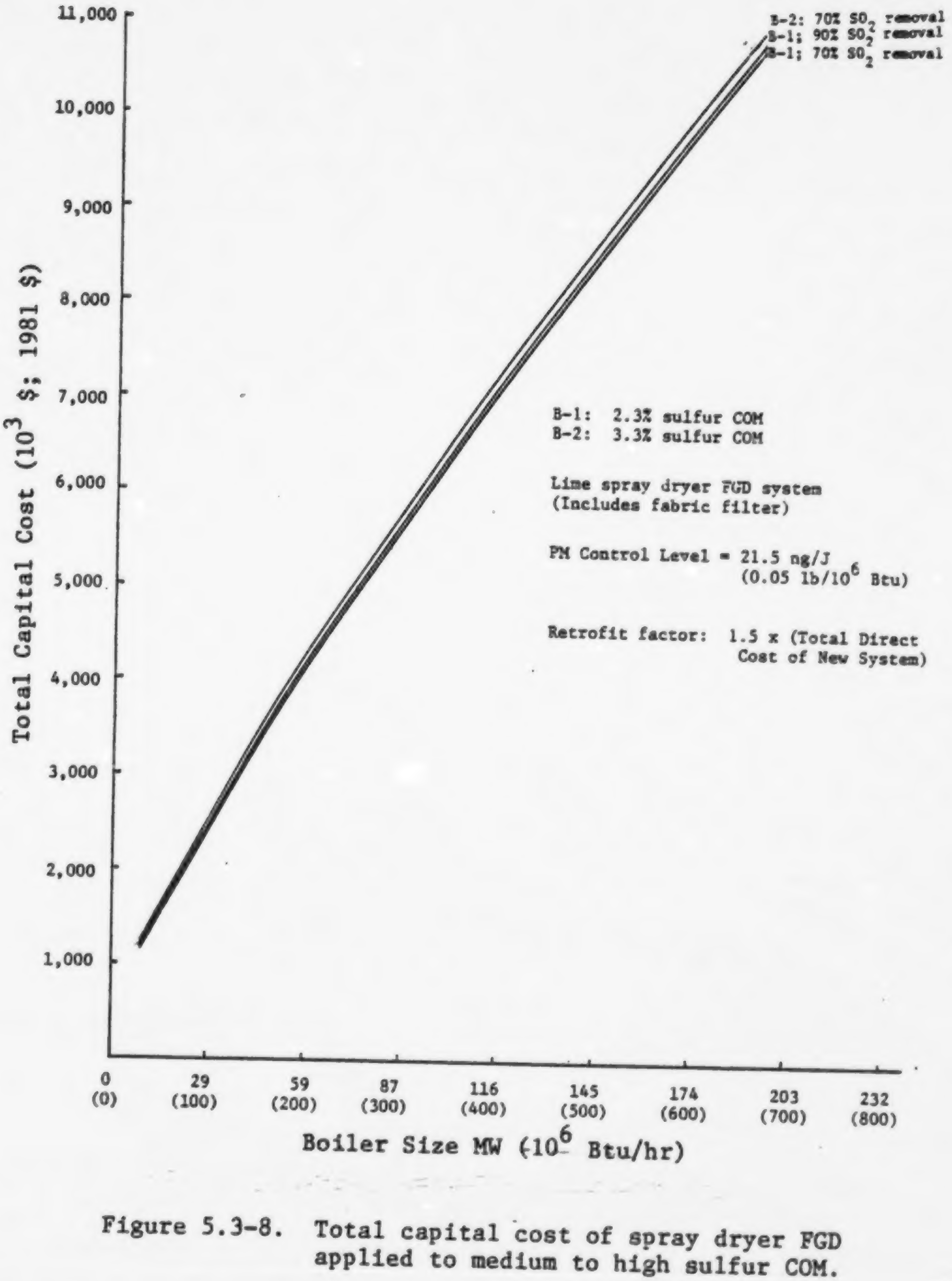


Figure 5.3-8. Total capital cost of spray dryer FGD applied to medium to high sulfur COM.

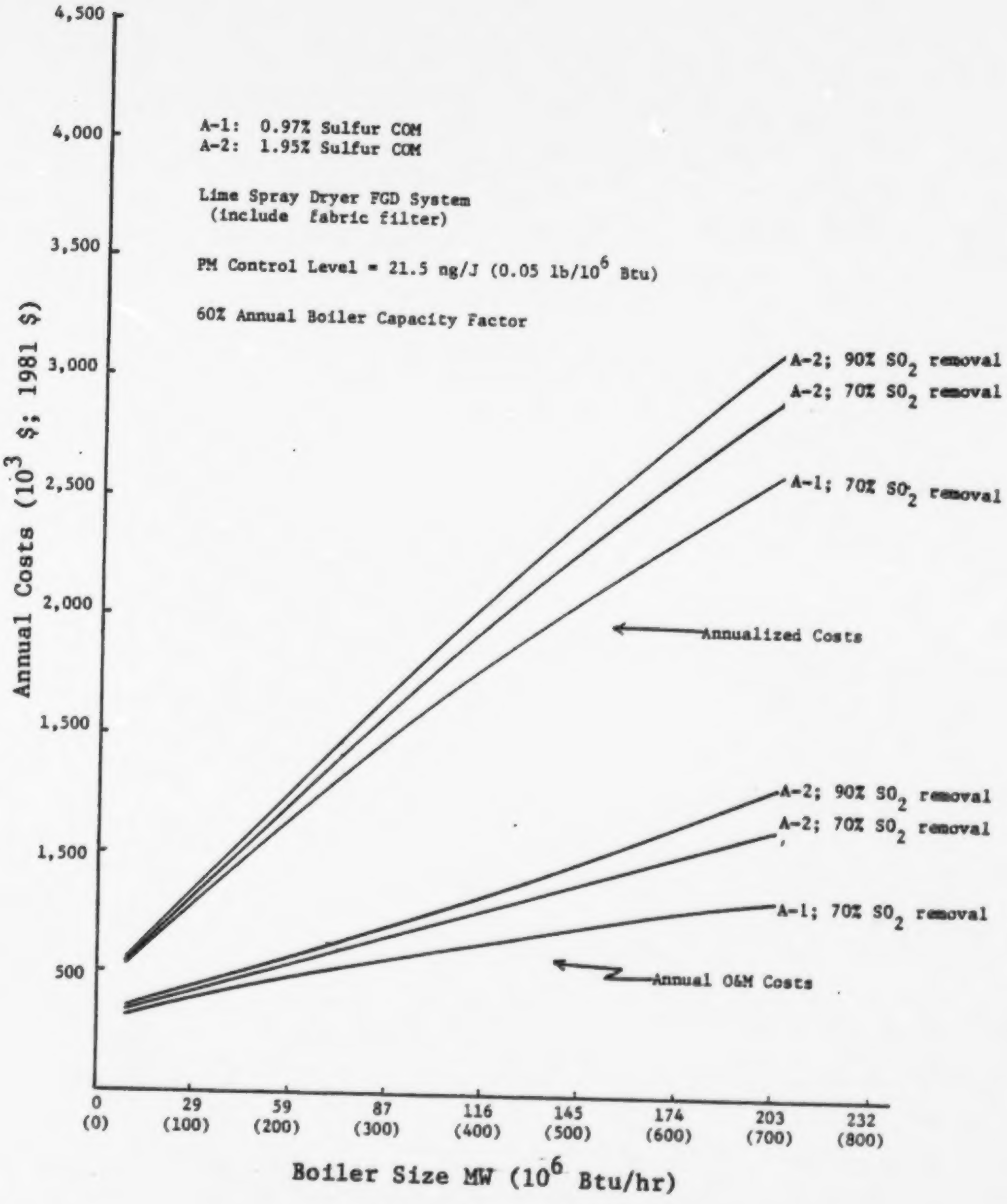


Figure 5.3-9. Annual O&M and annualized costs of spray dryer FGD applied to low sulfur COM units.

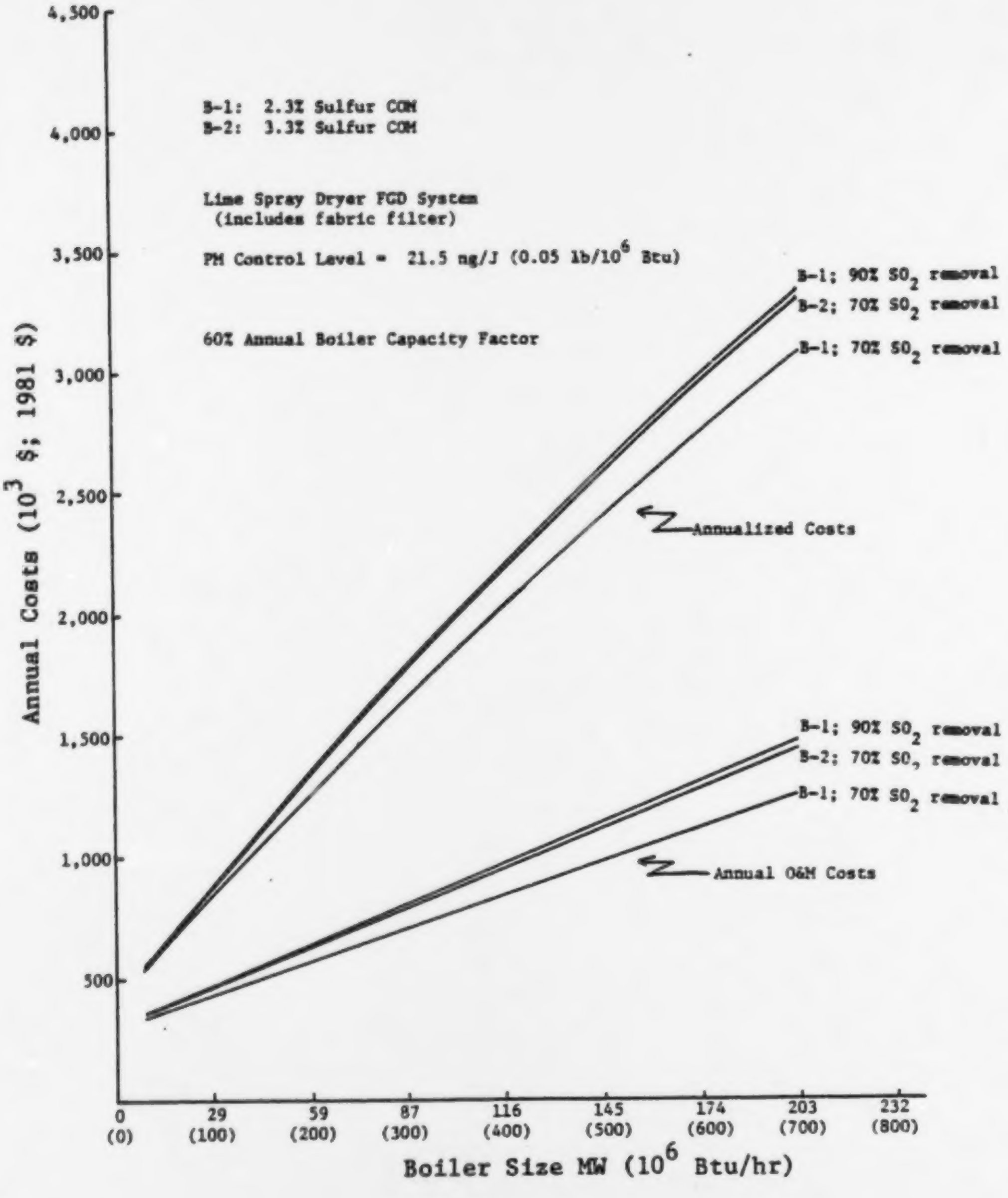


Figure 5.3-10. Annual O&M and annualized costs for spray dryer FGD applied to medium to high sulfur COM units.

Figures 5.3-9 and 5.3-10 also show annualized costs for the various cases examined. For the lower sulfur COM fuels, spray dryer system annualized costs range from about \$550,000 to between \$2.6 and \$3.1 million for the boiler size range examined. Similar costs for the high sulfur COM fuels range from about \$550,000 for a 30×10^6 Btu/hr boiler up to between \$3.1 and \$3.3 million for a 700×10^6 Btu/hr boiler.

Figure 5.3-11 shows normalized annualized costs (heat input basis) for the range of spray dryer cases examined. For the bounding cases (70 percent SO_2 removal on low sulfur COM and 90 percent SO_2 removal on 2.3 percent sulfur COM), the normalized annualized costs range from \$3.37 to \$3.58/10^6 Btu heat input for a 30×10^6 Btu/hr boiler to between \$0.71 and \$0.91/10^6 Btu for a 700×10^6 Btu/hr boiler. Normalized costs for the other cases examined would fall within the boundry cases illustrated in Figure 5.3-11.

5.3.2.3 Cost Effectiveness

Cost effectiveness of spray dryer FGD systems is difficult to calculate, and the resulting values may not be meaningful since a substantial portion of the system costs are attribuatble to the fabric filter. Although it would be possible to calculate a cost per ton of SO_2 removed with the spray dryer system, the values would be artifically high due to the fabric filter system costs and failure to account for the significant amount of PM removed.

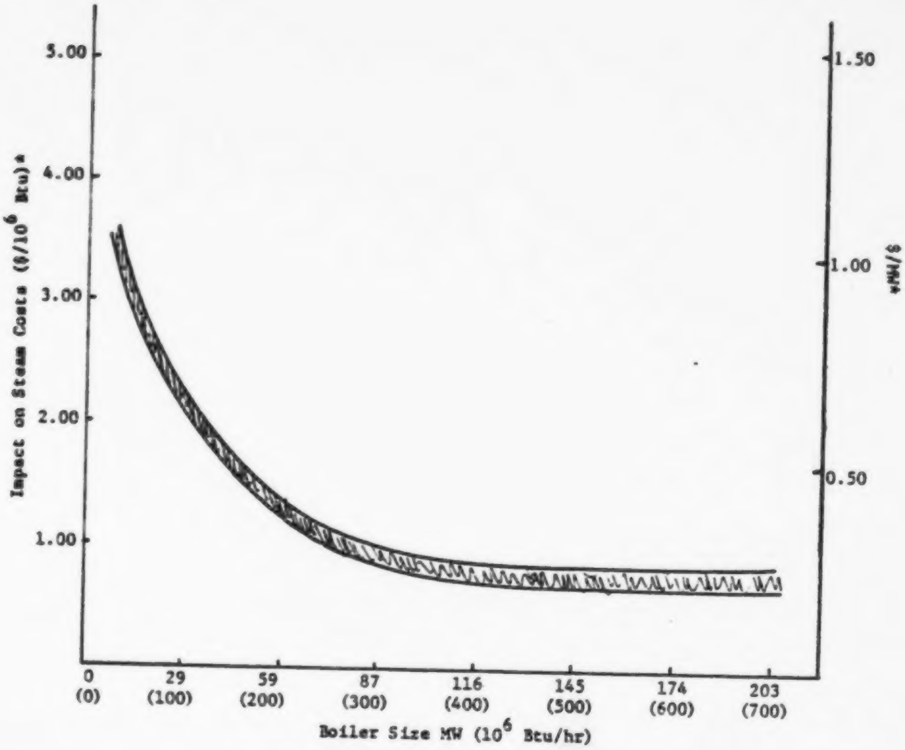
However, most of the same general trends shown earlier for wet FGD cost effectiveness would be observed for spray drying systems -- decreasing cost per ton of SO_2 removed with increasing boiler size and increasing COM sulfur content. Spray dryer cost effectiveness may also improve as the SO_2 removal is increased, although the increased reagent requirements for higher SO_2 removals will offset this trend to some degree.

5.3.3 Dry Injection Systems Costs

5.3.3.1 Capital Costs

Estimated capital costs for dry injection of nahcolite, which include the costs of a retrofitted fabric filter, are shown in Figure 5.3-12. The costs are shown as a function of boiler size for low and high sulfur content COMs and are based on 70 percent SO_2 removal.

The dry injection costs have a somewhat higher degree of uncertainty that wet FGD system or spray dryer FGD costs. This higher uncertainty is due primarily to a lack of large-scale facility design and operating data for the dry injection process. The capital costs of the dry feeders, blowers, and fans were scaled down from literature estimates of dry injection costs for large power plants burning low and high sulfur coals.[9] Fabric filter costs were based on those developed earlier in this study (Section 5.2).



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*Heat input basis

Figure 5.3-11. Range of impact of spray drying FGD on steam costs.

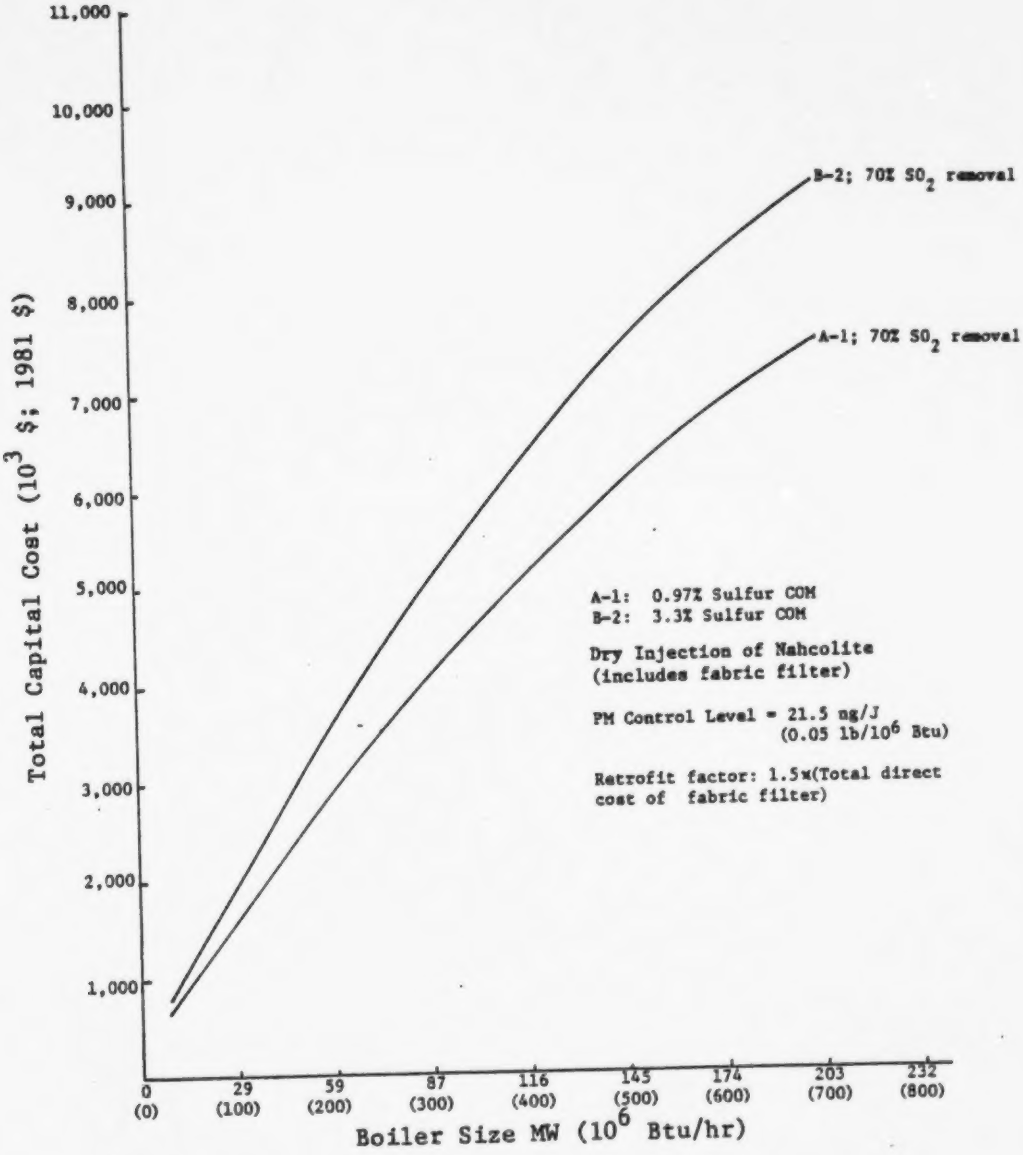

Figure 5.3-12. Total capital cost of dry injection applied to low and high sulfur COM units.

For a 0.97 percent sulfur COM, Figure 5.3-12 shows capital costs of the dry injection system to range from \$1.4 to \$7.3 million for the boiler sizes examined. Similar cost for a 3.3 percent sulfur COM range from \$1.7 to \$8.2 million. The retrofitted fabric filter accounts for 50 to 80 percent of the total dry injection system turnkey costs depending on boiler size and sulfur content. The difference in capital costs between the low and high sulfur COM applications is the result of substantially larger nahcolite handling equipment required for the high sulfur COM case. Figure 5.3-12 shows that this difference in capital costs becomes more significant as the boiler size increases.

5.3.3.2 Annual O&M and Annualized Costs

The annual O&M and annualized costs for nahcolite dry injection are shown in Figure 5.3-13. This figure shows the strong dependency of O&M costs on COM sulfur content (as well as boiler size). For the low sulfur COM ("A-1") annual O&M costs range from \$357,000 for a 30 x 10^6 Btu/hr boiler to \$ 1.35 million for a 700 x 10^6 Btu/hr boiler. For the 3.3 percent sulfur COM ("B-2"), annual O&M costs range from \$414,000 to \$3.2 million for the same boiler sizes.

The major component of the annual O&M costs for the dry injection system is the nahcolite cost, especially for the larger boilers and for higher sulfur COM. Nahcolite costs are also quite uncertain, since the chemical is not currently marketed.* In this study, a delivered price of \$38/ton (\$1978) was used to represent the cost of crushed and ground nahcolite. This price was based on data from two previous literature studies.[9,10]

Figure 5.3-13 shows annualized costs for the low sulfur COM case to range from \$455,000 to \$2.5 million for the boiler size range examined. Due to the relatively low capital charges (low capital costs) and nahcolite costs, the annualized costs for the low sulfur coal case are less than the annual O&M costs for the high sulfur COM case. Annualized costs for the high sulfur case range from \$541,000 to \$4.6 million, 20 to 30 percent higher than the low sulfur COM dry injection annualized costs, depending on boiler size. The largest annualized cost differences between high and low sulfur applications are observed for large boilers.

5.3.4 Comparison of FGD System Costs

Figures 5.3-14(a&b) provide a comparison of capital costs for the three FGD systems evaluated as a function of boiler size and COM sulfur content.

Figure 5.3-14a shows the comparison for low sulfur COM units (0.97 percent sulfur COM). The costs are based on the 70 percent SO_2 removal case [a controlled SO_2 emission level of 168 ng SO_2/J (0.4 lb/10^6 Btu)]. Up to a boiler size of about 200 x 10^6 Btu/hr dry injection has the lowest capital costs. However, for boilers larger than

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*Multimerals Corporation is currently obtaining environmental impact data on nahcolite mining. Annual commercial production of a minimum of 1 million tons of nahcolite could be available in about 4 years.

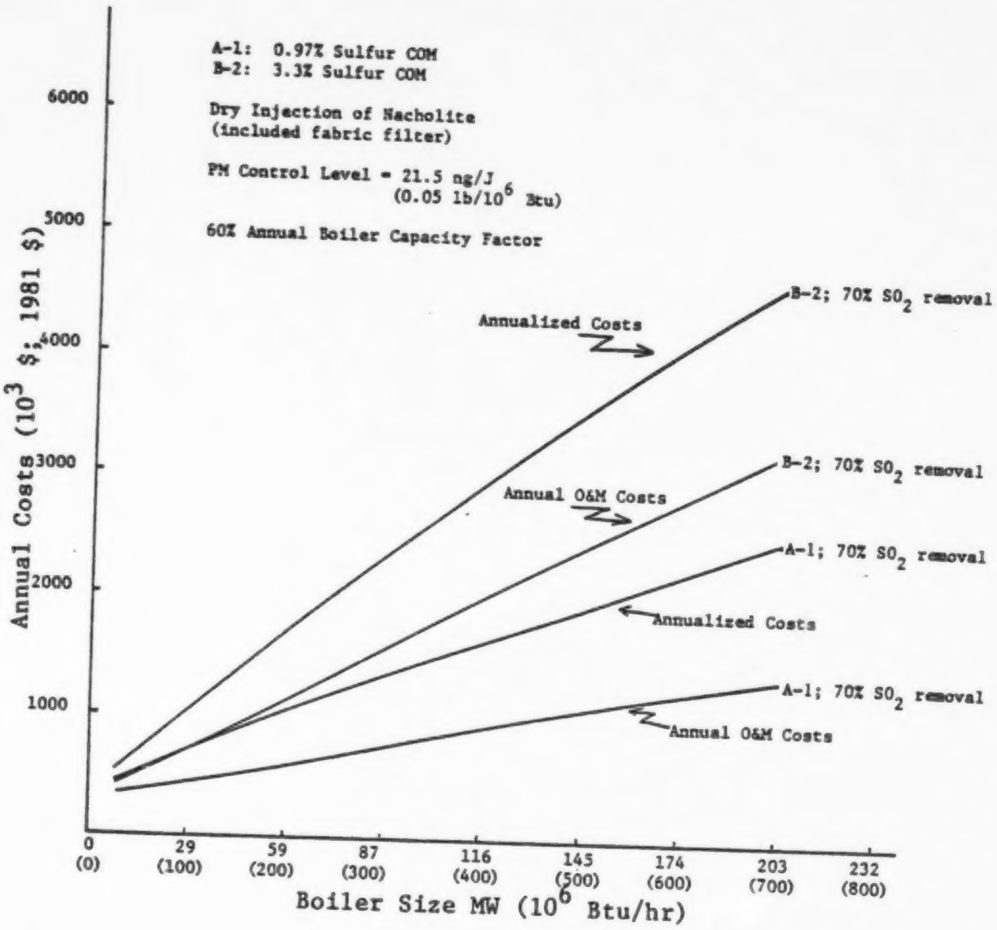
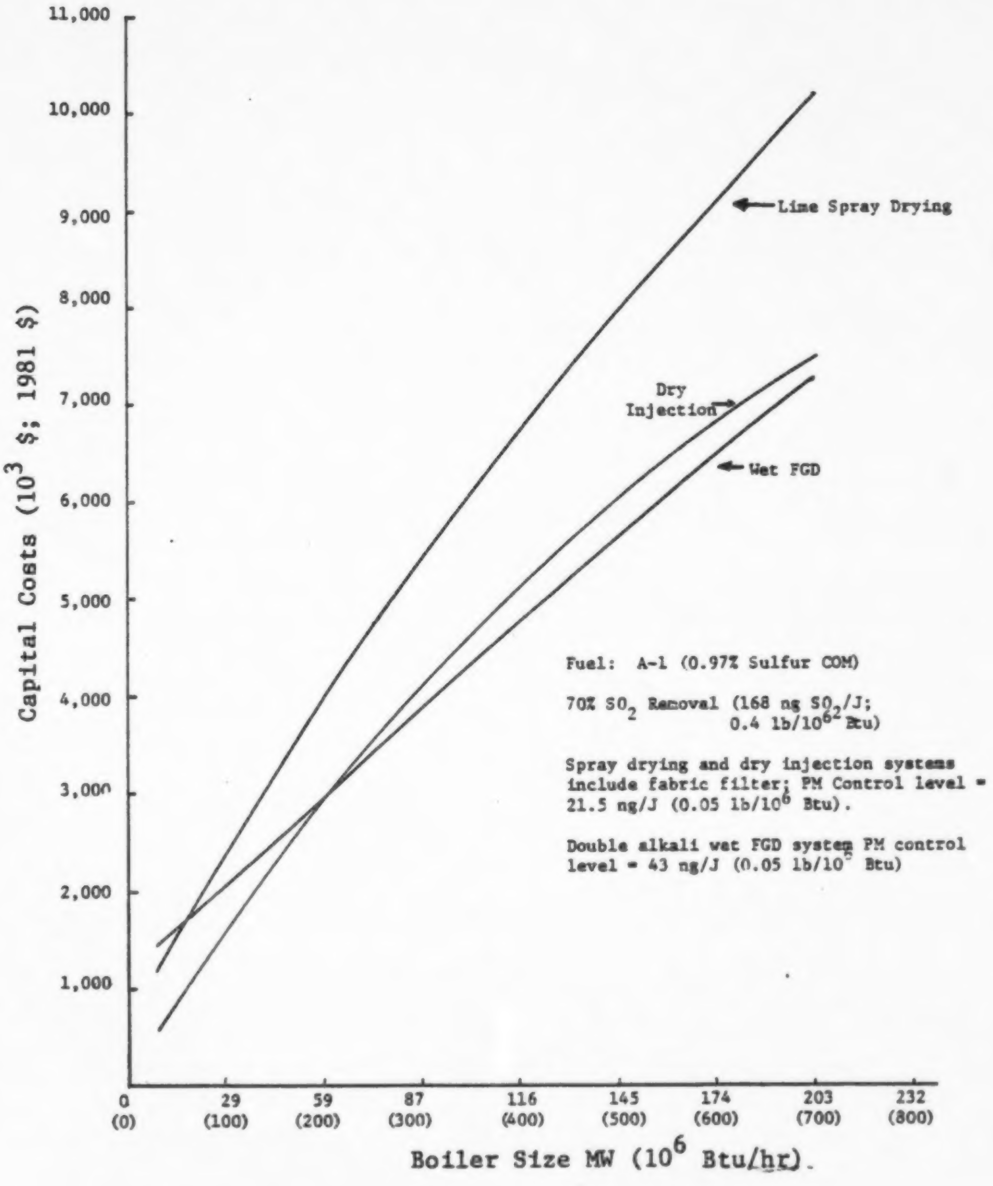


Figure 5.3-13. Annual O&M annualized costs of dry injection applied to low and high sulfur COM units.



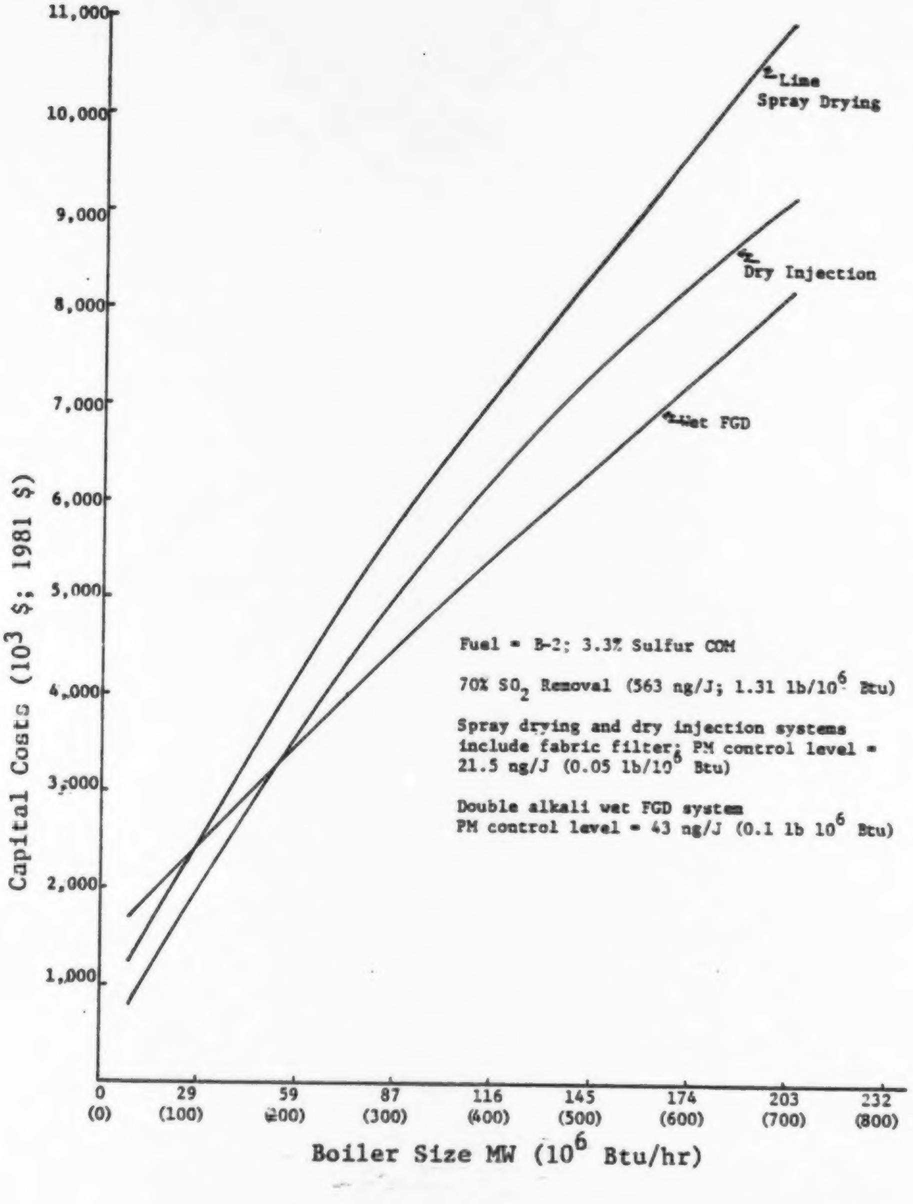
Fuel: A-1 (0.97% Sulfur COM)

70% SO_2 Removal (168 ng SO_2/J; 0.4 lb/10^6 Btu)

Spray drying and dry injection systems include fabric filter; PM Control level = 21.5 ng/J (0.05 lb/10^6 Btu).

Double alkali wet FGD system PM control level = 43 ng/J (0.05 lb/10^6 Btu)

Figure 5.3-14a. Comparison of FGD system capital costs - low sulfur COM.



Fuel = B-2; 3.3% Sulfur COM

70% SO_2 Removal (563 ng/J; 1.31 lb/10^6 Btu)

Spray drying and dry injection systems include fabric filter; PM control level = 21.5 ng/J (0.05 lb/10^6 Btu)

Double alkali wet FGD system
PM control level = 43 ng/J (0.1 lb 10^6 Btu)

Figure 5.3-14b. Comparison of FGD system capital costs - high sulfur COM.

this size, wet FGD has the lowest capital cost of the three systems. This result is due primarily to the use of a fabric filter in the spray dryer and dry injection systems. The reader should keep in mind the lower PM emission control levels achievable with fabric filters, relative to a wet FGD system used for combined SO_2/PM removal. An ESP would likely be required upstream of the FGD to achieve the same PM emission level.

Figure 5.3-14b shows the same trends in relative capital costs of the FGD systems applied to high sulfur COM units.

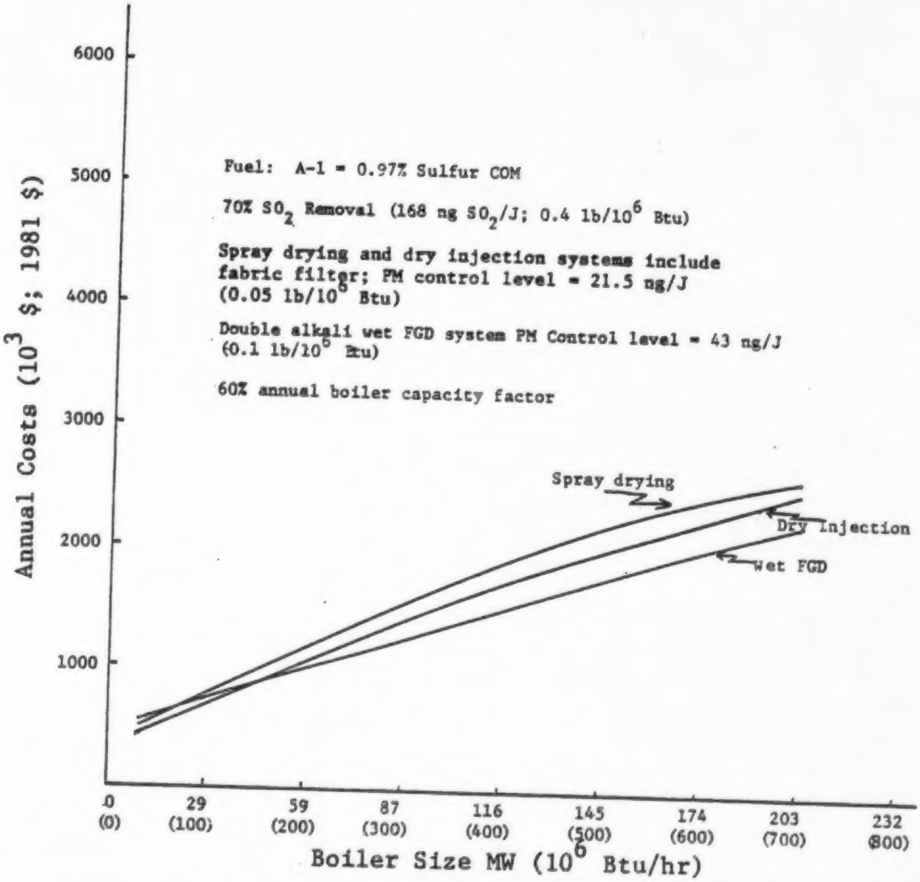
Comparisons of the annualized costs for the three FGD systems are presented in Figures 5.3-15a and b. Figure 5.3-15a shows all processes to be relatively close for low sulfur COM applications, but wet FGD also has the lowest annualized cost for boilers above about 200 x 10^6 Btu/hr. Wet FGD is also the least expensive system for high sulfur COM applications (Figure 5.3-15b), while dry injection has the highest annualized costs.

It should be noted that the comparisons presented are based on 70 percent SO_2 removal, an annual boiler capacity factor of 60 percent, and specific reagent costs. The relative costs of the three FGD systems for specific applications may be altered due to site-to-site variations in SO_2 removal, boiler capacity, reagent costs, or availability of existing equipment to reduce retrofit costs.

5.4 LOW SULFUR COM COSTS

This section presents costs for low sulfur COM fuels. Low sulfur COM is a possible alternative to the use of FGD for compliance with SO_2 emission regulations. As shown in Table 5.4-1, several different low sulfur COM compositions were examined. The fuel prices shown in Table 5.4-1 were taken from the basis for a current COM study being conducted for EPRI.[11] The fuel prices represent contract prices for oil and utility steam coal delivered to an Eastern COM preparation plant. It should be noted that COM fuel costs presented in the following sections do not include the costs of COM preparation or delivery. COM preparation costs are difficult to quantify given the current state of COM preparation technology and market development. However, much of the COM cost data presented in this section are expressed relative to the use of a higher sulfur COM, the cost of which also does not include preparation or delivery. The rest of the COM cost data are presented as a function of COM sulfur level or COM composition. Thus, since COM preparation and delivery costs are not likely to vary with COM sulfur content, the cost data are valid on a relative basis.

Another factor not included in this analysis of low sulfur COM costs is the potential impact of demand for lower sulfur COM fuels on their supply and price. Suppliers of low sulfur COMs may be in a position to charge a greater premium for lower sulfur COM fuels beyond the premium reflected in the costs of the coal and oil used to make the COM. Analysis of this factor is, however, beyond the scope of this study. The cost information presented



Fuel: A-1 = 0.97% Sulfur COM

70% SO_2 Removal (168 ng SO_2/J; 0.4 lb/10^6 Btu)

Spray drying and dry injection systems include fabric filter; PM control level = 21.5 ng/J (0.05 lb/10^6 Btu)

Double alkali wet FGD system PM Control level = 43 ng/J (0.1 lb/10^6 Btu)

60% annual boiler capacity factor

Figure 5.3-15a. Comparison of FGD system annualized costs - low sulfur COM.

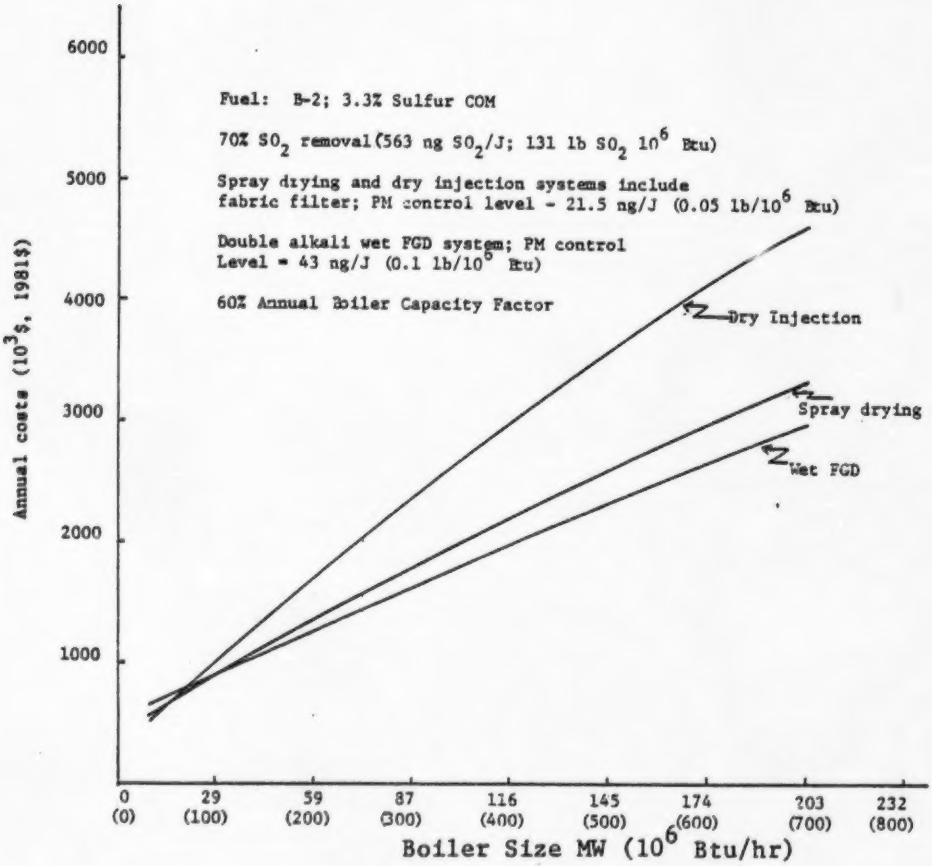


Figure 5.3-15b. Comparison of FGD system annualized costs-high sulfur COM.

TABLE 5.4-1. LOW SULFUR COM FUELS EXAMINED[a]

COM Components Fuel Price[b] ($/$10^6$Btu)		Uncontrolled SO_2 Emissions ng/J (lb/10^6Btu)		
Coal	Oil	30% Coal COM	40% Coal COM	50% Coal COM
0.7% S ($1.25)	0.5% S ($6.35)	305 (0.71)	331 (0.77)	357 (0.83)
0.7%S ($1.25)	0.8% S ($6.10)	404 (0.94)	413 (0.96)	426 (0.99)
0.7% S ($1.25)	1.5%S ($5.85)	628 (1.46)	606 (1.41)	585 (1.36)
1.2% S ($1.20)	0.8% S ($6.10)	503 (1.17)	550 (1.28)	598 (1.39)
2.0% S ($1.10)	0.5% S ($6.35)	572 (1.33)	- -	- -

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[a] All coals assumed to have heating value of 12,500 Btu/lb; Oils have heating value of 18,500 Btu/lb. Calculation of SO_2 emission rate based on 100% of fuel sulfur emitted as SO_2.

[b] Reference 10, $ 1981.

in the following sections should therefore be interpreted with these considerations in mind. Also, because coal and oil prices are subject to significant variation the final portion of this section deals with the sensitivity of COM fuel costs to coal and oil prices.

Figure 5.4-1 shows the COM fuel cost as a function of composition (coal and oil sulfur content) and percent coal in the COM. The fuel costs are expressed in terms of $\$/10^6$ Btu. Figure 5.4-1a shows the costs of COMs with uncontrolled SO_2 emissions of less than 430 ng/J (1.0 lb/10^6 Btu) (see Table 5.4-1). The cost of the COM prepared from 0.7 percent S coal and 0.5 percent S oil ranges from \$3.25 to \$5.35/10^6 Btu for coal concentrations of from 60 to 20 percent, respectively. Similar costs for COM made with the same sulfur content coal and oil of a slightly higher sulfur content (0.8 percent S) range from \$3.15 to \$5.10/10^6 Btu.

Figure 5.4-1b shows fuel costs for different COM compositions with uncontrolled SO_2 emissions of less than 1.5 lb/10^6 Btu (See Table 5.4-1). Costs for these fuels are slightly less than those for the lower sulfur COMs shown in Figure 5.4-1a, ranging from about \$3.15/10^6 Btu for a 60 percent COM to between \$4.85 and \$5.00/10^6 Btu for a 20 percent COM.

As shown in Figure 5.4-1, COM fuel costs decrease with (1) increasing coal or oil sulfur content and (2) increasing percentages of coal in the COM. However, Table 5.4-1 indicates that uncontrolled SO_2 emissions may either increase or decrease with increasing percentages of coal, depending on coal and oil sulfur content. For example, SO_2 emissions from a COM made with 0.7 percent sulfur coal and 0.5 or 0.8 percent sulfur oil increase as the percentage of coal in the COM is increased. However, SO_2 emissions decrease as COM coal content increases when the COM is made with a 1.5 percent sulfur oil. [These trends may, of course, be altered if heating values of the coal or oil are significantly different from those used in this study.]

5.4.1 Comparison With Wet FGD Costs

Figure 5.4-2 shows the annualized costs of using three low sulfur COMs as a function of boiler size. The COM costs are calculated relative to the cost of using a 2.3 percent sulfur COM using the following expression:

$$ANC_{COM}(\text{low S}) = [C_{COM}(\text{low S}) - C_{COM}(\text{high S})][Q][CF]$$

where $ANC_{COM}(\text{low S})$ = annual cost of low sulfur COM;

$C_{COM}(\text{low S})$ = low sulfur COM cost, $\$/10^6$ Btu;

$C_{COM}(\text{high S})$ = 2.3% S COM cost, $\$/10^6$ Btu;

Q = boiler size, 10^6 Btu/hr; and

CF = hours/yr boiler operation (5,256 hrs)

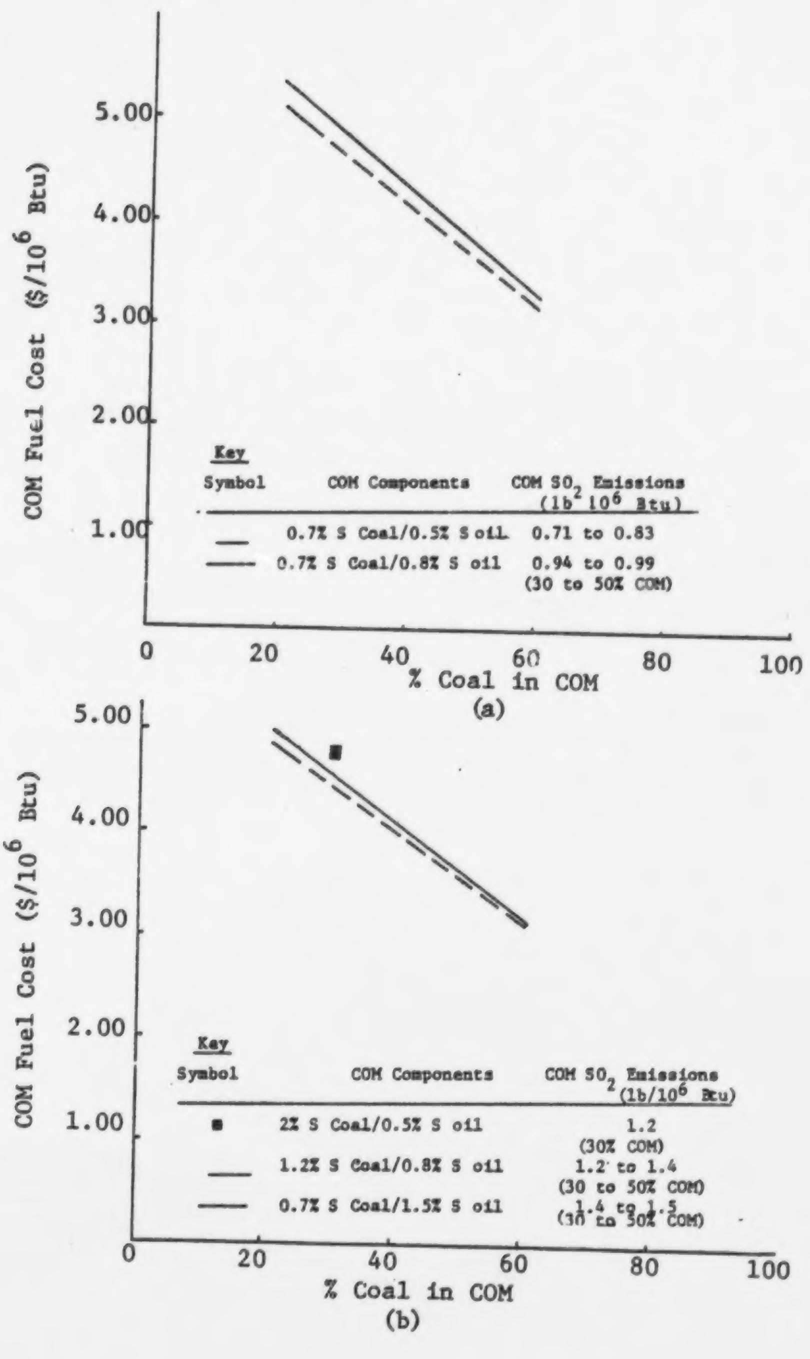

Figure 5.4-1. Costs of low sulfur COMs (does not include delivery or preparation).

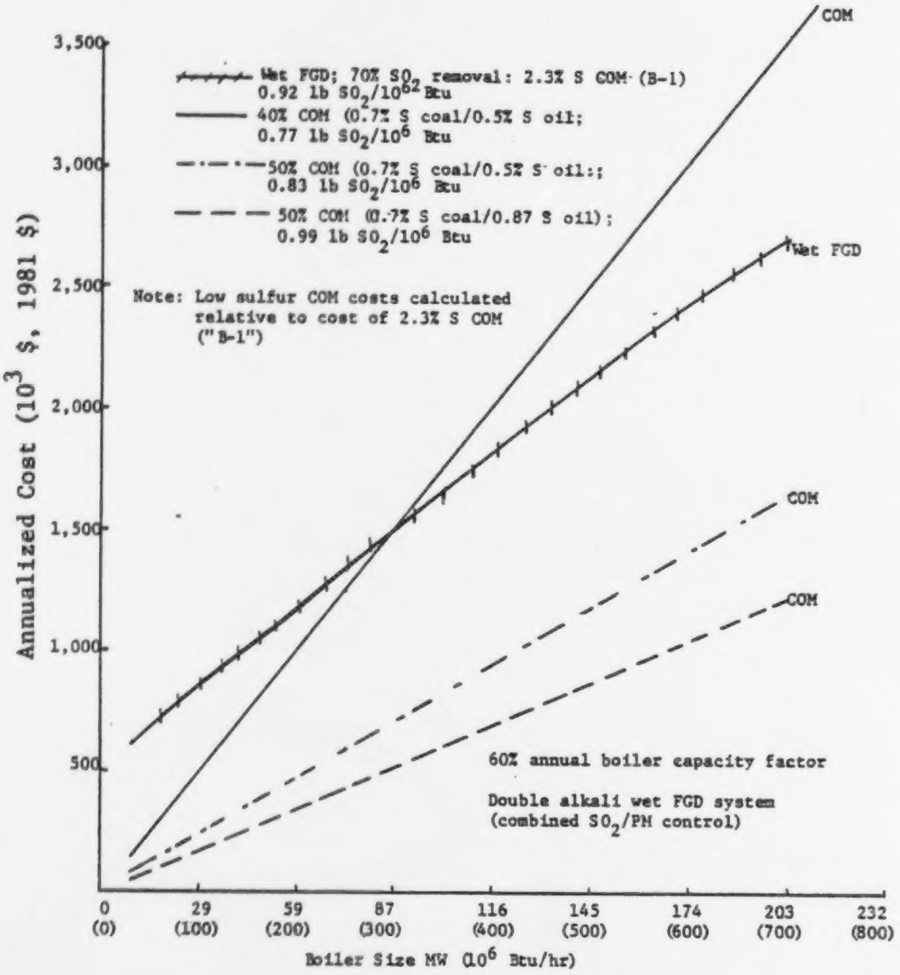

Figure 5.4-2. Comparison of wet FGD and low sulfur COM annualized costs.

The cost of a wet FGD system operating at 70 percent SO_2 removal is shown for comparison. Emissions of SO_2 in each case are less than 430 ng/J (1.0 lb/10^6 Btu).

Figure 5.4-2 shows that wet FGD is more expensive than the use of the low sulfur COMs with 50 percent coal. However, use of the 40 percent coal COM (made with 0.7 percent S coal and 0.5 percent S oil) is more expensive than FGD for boilers larger than about 300 x 10^6 Btu/hr. Of course, the boiler size where FGD becomes less costly than low sulfur COM will depend on boiler capacity factor. Both FGD costs and annual COM costs depend directly on boiler capacity factor, although COM costs are generally affected more strongly by changes in capacity factor. It is likely that FGD will be less costly than low sulfur COM only for large boilers operated at relatively high annual capacity factors (greater than about 0.6).

One factor especially important in comparing FGD and low sulfur COM costs is not included in Figure 5.4-2: the PM control device that may be required for the low sulfur COM case. The cost of an ESP or fabric filter may significantly impact the total combined SO_2/PM control costs for low sulfur COM units. Section 5.5 provides further comparison of FGD costs versus the use of low sulfur COM and a fabric filter for combined SO_2/PM control.

5.4.2 Cost Effectiveness

Figure 5.4-3 shows the cost effectiveness of using three different low sulfur COMs to limit SO_2 emissions. The cost effectiveness is calculated by the following expression:

$$CE_{COM}(\text{low S}) = \frac{C_{COM}(\text{low S}) - C_{COM}(\text{high S}) \quad (2000\ \text{lb/ton})}{[E_{SO2}(\text{high S}) - E_{SO2}(\text{low S})]}$$

where CE_{COM} = Cost effectiveness of low sulfur COM, \$/ton;

C(low S) = Cost of low sulfur COM, \$/10^6 Btu;

C_{COM}(high S) = Cost of 2.3% sulfur COM, \$/10^6 Btu;

E_{SO2}(high S) = Uncontrolled SO_2 emissions from 2.3% S COM, lb/10^6 Btu; and

E_{SO2}(low S) = SO_2 emissions from low S COM, lb/10^6 Btu.

Figure 5.4-3 shows the cost per ton of SO_2 ranging from \$370 to \$835 for the cases examined. The cost effectiveness of wet FGD (70 percent SO_2 removal, 60 percent capacity factor) for the 2.3 percent sulfur COM ranges from

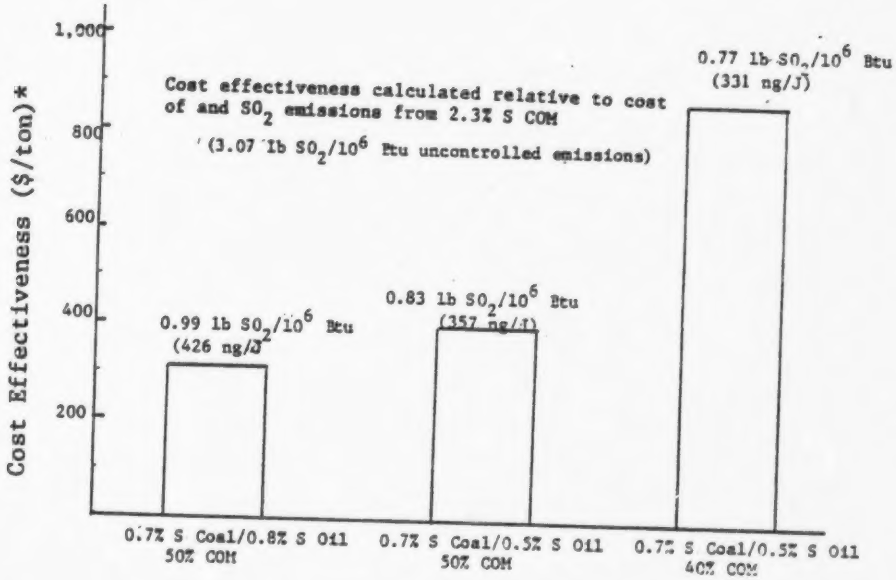

Figure 5.4-3. Cost effectiveness of low sulfur COMs.

*To convert to $/Mg, divide by 0.908.

\$680/ton to \$3,720/ton for the boiler sizes of 700 to 30 x 10^6 Btu/hr respectively. [As shown by the above expression, cost effectiveness of low sulfur COM is not a function of boiler size or capacity factor.]

5.4.3 Sensitivity of COM Fuel Costs to Coal and Oil Prices

The price of coal and oil used to make COM may vary substantially with COM preparation plant location, quality of coal and oil, and the type of contract under which the coal or oil is purchased. These variations, as well as the type of preparation process and local or regional fuel market considerations, will determine the COM fuel cost.

In the previous subsections, only a limited number of coal and oil types and prices were examined. However, variations in coal and oil properties and prices can be an important factor in evaluating, for example, the costs of using low sulfur COM versus FGD.

Figure 5.4-4 is a nomograph that can be used to determine the COM "raw materials" cost given certain parameters. ("Raw materials" cost refers to cost of coal and oil delivered to COM preparation plant, and does not include COM preparation or transportation.) The nomograph can be employed as in the example shown (Table 5.4-2 and points A-M on Figure 5.4-4), to determine COM cost (\$/10^6 Btu) given the following information:

Quantity	Value for Example in Table 5.4-2 and Figure 5.4-4
Coal price, \$/ton	\$25/ton
Oil price, \$/barrel	\$35/barrel
Oil gravity, °API	15°API
Coal heating value; Btu/lb	12,500 Btu/lb
Weight percent coal in COM; %	50% COM

Details on the development of the nomograph can be found in Reference 10.

Figure 5.4-5 shows the sensitivity of COM fuel costs to \$/10^6 Btu changes in coal and oil prices for a particular COM composition.

A \$1/10^6 Btu increase in the coal price (\$1/10^6 Btu to \$2/10^6 Btu) leads to about a 9 percent increase in the COM fuel costs. A \$1/10^6 Btu increase in the oil price (\$6/10^6 Btu to \$7/10^6 Btu) yields an 8 percent increase for the 50 percent COM and about a 16 percent increase for the 30 percent COM.

5.5 ANNUALIZED COST COMPARISON FOR COMBINED SO_2/PM CONTROL

The alternatives examined in the previous sections were FGD for combined SO_2/PM control, low sulfur COM for SO_2 control, and fabric filters and ESPs for PM control. The use of low sulfur COM and an ESP or a fabric

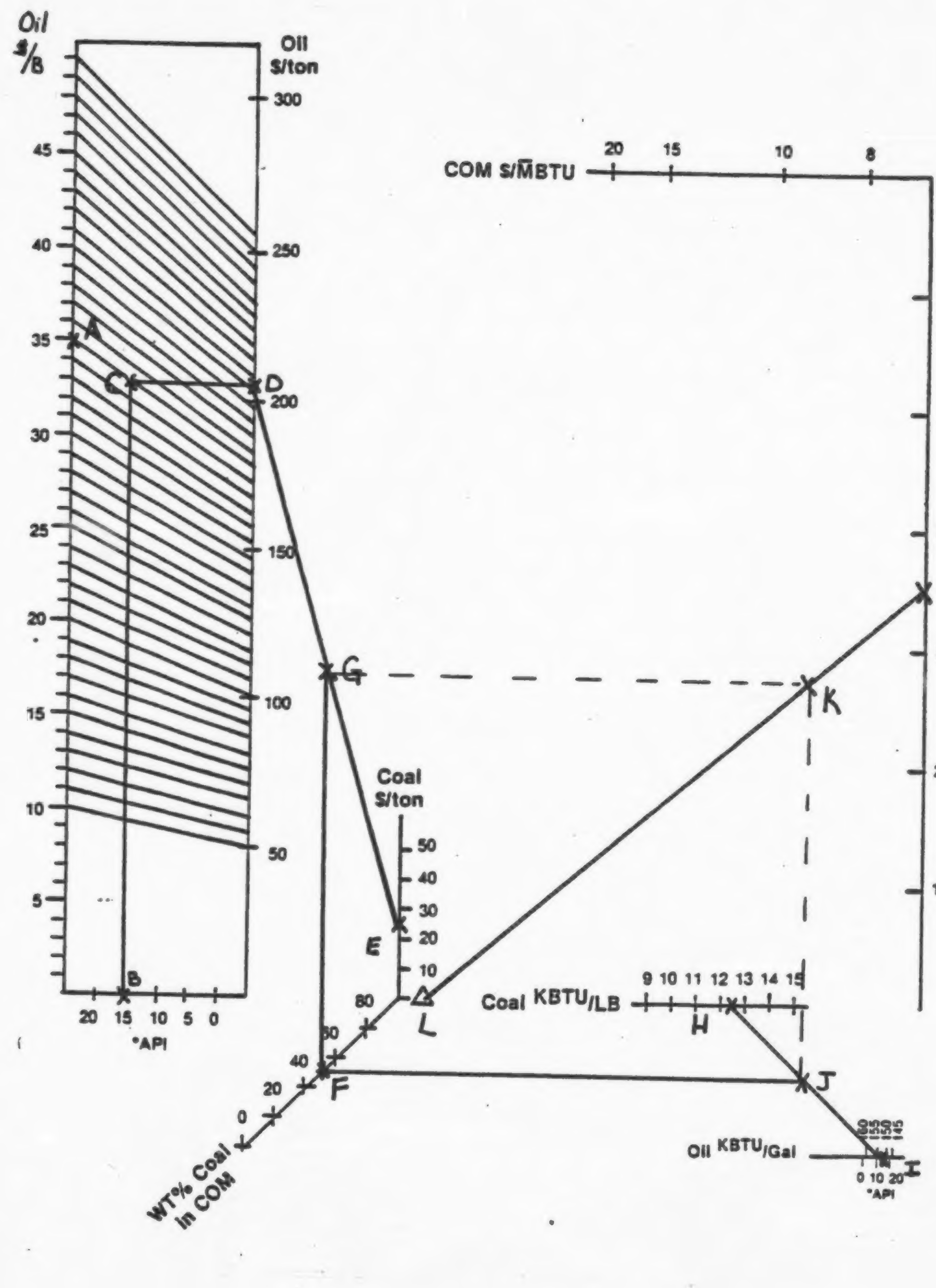

Figure 5.4-4. COM raw materials cost nomograph. (Reference 10).

TABLE 5.4-2. DIRECTIONS AND EXAMPLE RAW MATERIALS COMPONENT OF COM PRICE NOMOGRAPH (Figure 5.4-4). (Reference 10).

		Example
	Determination of oil price per ton.	
	A - Oil Price $/B	= $35/B (given)
	B - Oil Gravity °API	= 15° API (given)
	C - Intersection of vertical projection of B on sloped line from A	
=	D - Horizontal projection of C to $/ton axis	= $206.85/ton
	Determination of COM price per ton:	
	E - Coal Price $/ton	= $25/ton (given)
	Form COM wt. price operating line DE	
	F - Wt. % coal in COM	= 50% (given)
=	G - Vertical projection of F on operating line DE	= $115.93/ton
	Determination of COM heating valve	
	H - Coal Heat Valve KBTU/lb	= 12,500 Btu/lb (given)
	I - Oil Heat Valve KBTU/gal or Gravity °API	= 15° API
	Form COM wt. heating valve operating line HI	
=	J - Horizontal projection of F on operating line HI	
	Determination of COM price; $/MBTU	
	K - Intersection of horizontal from G and vertical from J	
	L - Price tie point	
=	M - Projection of line LK to final COM price	= $3.70/MBTU

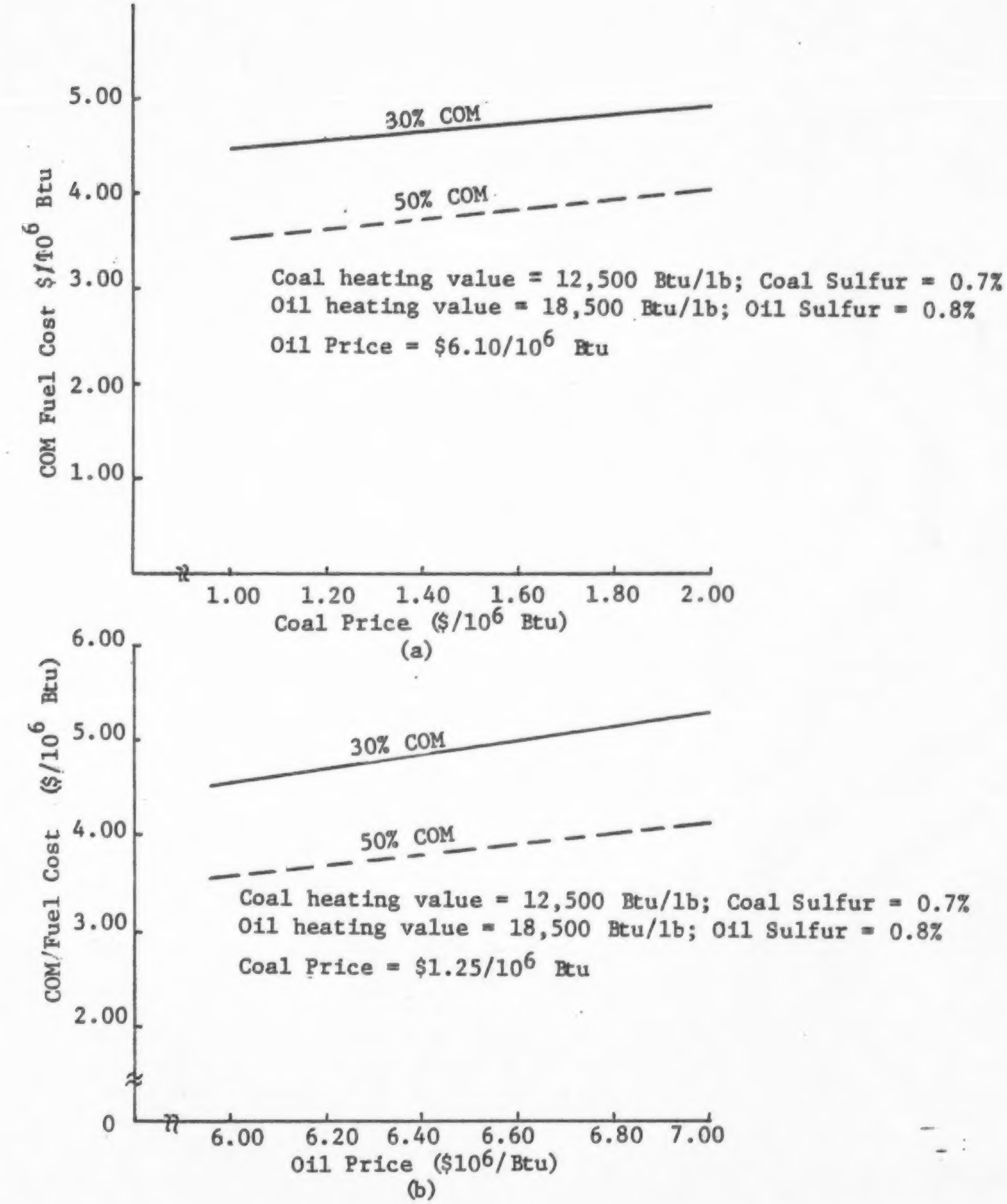

Figure 5.4-5. COM fuel cost sensitivity to coal and oil prices.

filter will also provide simultaneous SO_2/PM control. The combined annualized cost of low sulfur COM and a fabric filter is compared to the costs of wet and dry FGD in Figure 5.5-1. The SO_2 and PM emission control levels achievable with these systems are:

SO_2: nominal 430 ng/J (1.0 lb $SO_2/10^6$ Btu) and

PM: 21.5 ng/J (0.05 lb/10^6 Btu) (dry FGD, fabric filter)

43 ng/J (0.1 lb/10^6 Btu) (wet FGD).

Figure 5.5-1 shows the 50 percent coal low sulfur COM/fabric filter combination to be the least expensive combined SO_2/PM control technique up to a boiler size of about 325 x 10^6 Btu/hr. Above the 325 x 10^6 Btu/hr size, wet FGD becomes the least expensive alternative. Both wet FGD and spray drying are less costly than the 40 percent coal low sulfur COM/fabric filter combination.

As stated in the previous sections, the relative cost of the combined SO_2/PM control alternatives shown in Figure 5.5-1 could be altered for specific COM applications. Factors that must be evaluated on a site-specific basis to determine the most economical SO_2/PM control alternative include:

- actual COM properties and price,
- local or regional labor and reagent costs,
- projected FGD system reliability,
- boiler capacity factor,
- waste disposal options and costs for FGD,
- applicable SO_2 emission standards,
- retrofit difficulty.

5.6 NO_x CONTROL COSTS

The costs of applying combustion modification NO_x controls to boilers converted to COM are highly boiler specific. The major equipment and boiler modification requirements for the four combustion modification techniques evaluated in this study are listed below:

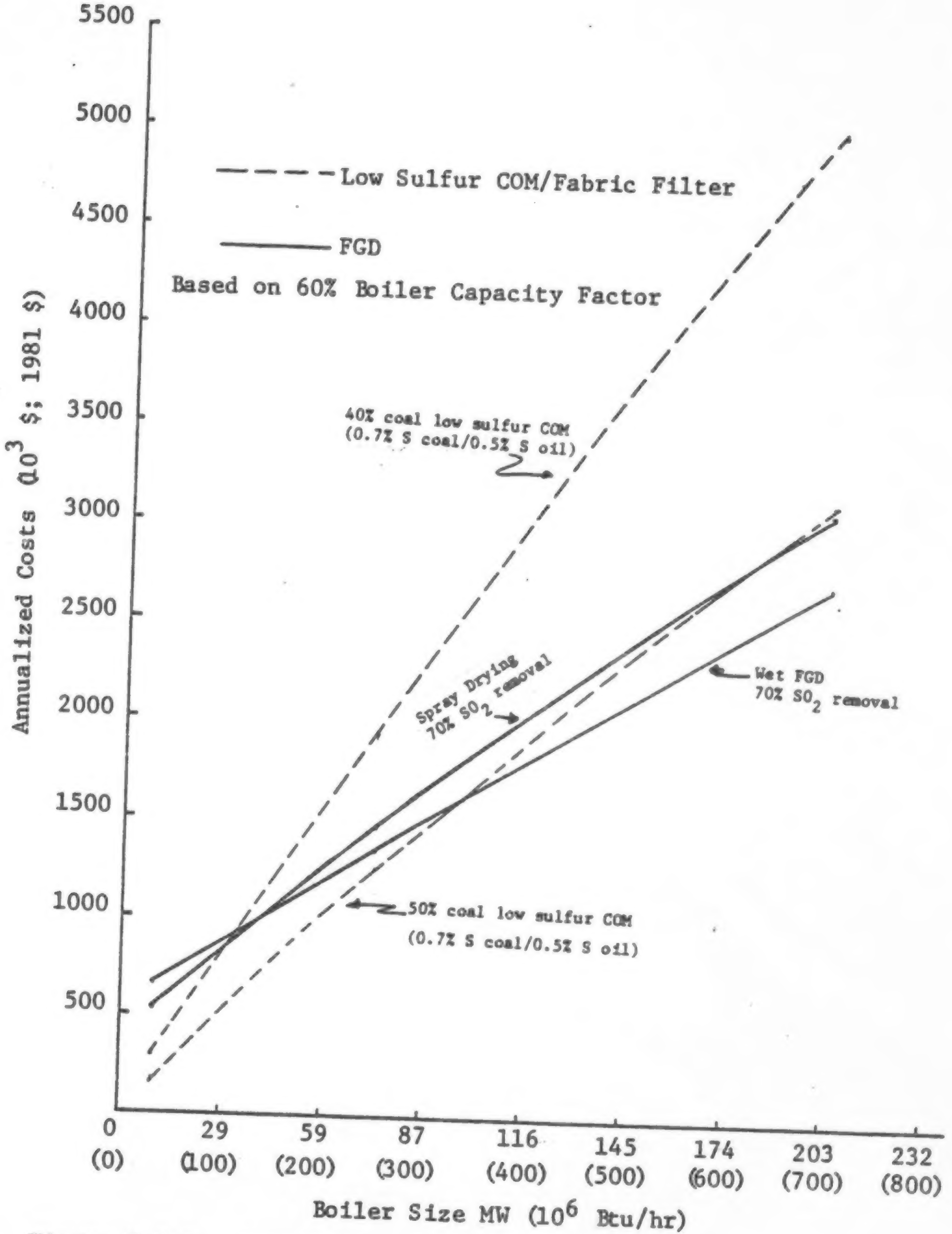

Figure 5.5-1. Comparison of annualized costs of alternatives for combined SO_2/PM control.

Technique	Major Equipment and Boiler Modification Requirements
Low excess air (LEA)	Automatic 0_2 control system
Staged combustion (SC)	Automatic 0_2 control system; secondary air ports if "burner out-of-service" configuration cannot be used. Modification of fuel delivery system for burners out-of-service.
Flue gas recirculation (FGR)	Automatic 0_2 control system; gas recirculation ductwork, increased fan capacity. Possible burner and windbox modifications.
Low-NO_x burners	New burners; automatic 0_2 control system.

For retrofit applications, the costs of installing the new equipment or modifying the boiler will depend strongly on the existing boiler design. Automatic 0_2 control systems are about $10,000 (uninstalled, $1981).

The principal annual cost component for all of these combustion modification techniques is the change in energy requirements due to boiler efficiency changes resulting from implementing the modification. For example, LEA is the least expensive combustion modification since it increases boiler efficiency. Staged combustion, on the other hand, is more expensive since it results in reduced boiler efficiency, thereby requiring additional fuel to maintain the same boiler capacity.

5.7 REFERENCES

1. U. S. Environmental Protection Agency. Contractors Procedures Manual for Development of Natural Emission Standards. Research Triangle Park, North Carolina, October 1978 and updates.

2. U. S. Environmental Protection Agency (Emission Standards and Engineering Division). Fossil Fuel-Fired Industrial Boilers - Background Information for Proposed Standards. Preliminary Draft. U.S. Environmental Protection Agency. Research Triangle Park, NC. June 1980. p. 6-17.

3. These assumptions result in maximum estimates of uncontrolled SO_2 and PM emission rates. For example, if a highly alkaline ash coal was used in the COM, some potential SO_2 may instead be retained in the bottom ash.

4. Jennings, M. S. and M. E. Kelly. (Radian Corporation). Costs of Sulfur Dioxide and Particulate Matter Emission Controls for Coal- and Oil-Fired Industrial Boilers. EPA Contract No. 68-02-3058. U. S. Environmental Protection Agency. Research Triangle Park, NC. September 1981. Volumes 1 and 2.

5. Ball, J. G. and W. R. Menzies (Radian Corporation). Flue Gas Desulfurization Cost Estimates for Acid Rain Studies. EPA Contract No. 68-02-3171. Task 12. U. S. Environmental Protection Agency. Research Triangle Park, NC. Volume I: Technical Report. September 1981. pp. 1-15, 1-16.

6. Kelly, Mary E. (Radian Corporation). Conversation with M. S. Jennings (Radian) about CE Plant Cost factor used in Industrial Boiler NSPS study. October 22, 1981.

7. Reference 1. pp. 4-3 to 4-9.

8. Dickerman, J. C. and K. L. Johnson (Radian Corporation). Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization. EPA-600/7-79-178c. U. S. Environmental Protection Agency. Research Triangle Park, NC. November 1979. Chapter 4.

9. Genco, J. M. et al. "The Use of Nahcolite Ore and Bag Filters for Sulfur Dioxide Emission Control." In: Journal of the Air Pollution Control Association. 25 (12):1244-1253.

10. Furlong, Dale A. et al. So_2 Removal Using Dry Sodium Compounds. (Presented at: AIChE 89th National Meeting. Portland, Oregon. August 17-20, 1980.)

11. Azarnoosh, Azarpoor et al. (Becttel Group, Inc). "Coal-Oil Mixtures as Utility Boiler Fuels." In: Proceedings of Third International Symposium on Coal-Oil Mixture Combustion. Orlando, Florida. April 1-3, 1981.

APPENDIX A

SUMMARY OF AVAILABLE COM TEST REPORTS

This Appendix lists the references for emission test data presented in Chapter 3. Other references containing information on COM emissions are also listed.

A large portion of the available emission data has been presented in papers delivered at the three Department of Energy (DOE) International Symposiums on Coal-Oil Mixture Combustion. There have been four such symposiums:

1st May 7-9, 1978; St. Petersburg, Florida

2nd November 27-29, 1979; Danvers, Massachusetts

3rd April 1-3, 1981; Orlando, Florida.

4th May 10-12, 1982; Orlando, Florida.

References taken from the proceedings of these symposiums are designated below. The symposium proceedings are available from:

National Technical Information Service
U. S. Department of Commerce
Springfield, Virginia 22161

The numerical designations given to the following references (A.1, A.2, etc.) correspond to those designations used in Chapter 3.

Site	Agency or Firm Involved in Tests	Reference
A.1	DOE-Pittsburgh Energy Technology Center (PETC)	Demeter, J. J. et al. Combustion of Coal-Oil Slurry in a 100 hp Firetube Boiler. PERC/RI-77/8. DOE-PERC. Pittsburgh, PA. May 1977.
A.2	DOE-PETC	Ekmann, J. M. et al. "Parametric Studies of COM Combustion" (1st Symposium Proceedings). May 1978.
A.3	DOE-PETC	Pan, Y. S. et al. Recent Coal-Oil Mixture Combustion at PETC. DOE/PETC/TR-80/5. DOE-PETC. Pittsburgh, PA. June 1980.
A.4	DOE-PETC	Pan, Y. S. "Effect of Coal Particle Size Consist on the Performance of a COM-Fired Boiler." (3rd Symposium Proceedings). April 1981.
A.5	DOE-PETC	De Rosier, R. "Environmental Assessment of a Watertube Boiler Firing A Coal/Oil Mixture — Volume 1: Technical Results." EPA Contract No. 68-02-3188, U. S. Environmental Protection Agency, Research Triangle Park, NC. September 1980.
A.6	General Motors Corporation (Several other agencies and companies also participated in GM tests.)	Brown, A. (ed.). Final Report on the General Motor's Corporation Powdered Coal-Oil Mixture Program. U. S. Department of Energy Report FE-2267-2. U. S. DOE. Washington, D. C. October 1977.
A.7	Adelphi University	Dooher, J. P. et al. "Feasibility Studies of Using a Coal/Oil/Water Emulsion and Coal/Oil/Mixtures as Clean Liquid Fuels." (2nd Symposium Proceedings). November 1979.
A.8	Adelphi University	Dooher, J. P. "Sulfur Dioxide Removal in the Combustion of Coal/Oil/Water Emulsions." (3rd Symposium Proceedings). April 1981.

Site	Agency or Firm Involved in Tests	Reference
A.9	Adelphi University	De Rosier, R. "Environmental Assessment of a Firetube Boiler Firing Coal/Oil/Water Mixtures — Volume 1: Technical Results." EPA Contract No. 68-02-3188, U. S. Environmental Protection Agency, Research Triangle Park, NC. November 1981.
A.10	New Brunswick Electric Power Commission	Whaley, H. et al. "An Assessment of the Environmental Emissions from a Utility Boiler Firing Beneficiated Coal-Oil Mixtures." (Presented at the 73rd Annual Meeting of the Air Pollution Control Association. Montreal, Quebec, Canada. June 22-27, 1980.)
A.11	Scotia Ligcoal	Poetschke, L. E. "Liquicoal Demonstration Project." (3rd Symposium Proceedings). April 1981.
A.12	Scotia Liqucoal	Castaldini, C. "Environmental Assessment of an Industrial Boiler Burning Coal/Oil/Water Mixtures — Volume 1: Technical Results. EPA Contract No. 68-02-3188, U. S. Environmental Protection Agency, Research Triangle Park, NC. September 1981.
A.13	Florida Power Corporation	Rodriquez, L. A. and Sell, F. R. "Florida Power Corporation/ Draw Power Corporation. Coal/Oil Composite Fuel Program." (1st Symposium Proceedings). May 1978.
A.14	Florida Power and Light Company	Schmidt, A. D. "Full-scale Tests Firing Coal-Oil Mixtures in a 400 MW Steam Generator." (3rd Symposium Proceedings). April 1981.

Site	Agency or Firm Involved in Tests	Reference
A.15	Acurex/U. S. Environmental Protection Agency	Brown, Richard A. Alternate Fuels and Low-NO$_x$ Tangential Burner Development Program EPA-600/7-79-050b. U. S. Environmental Protection Agency. Research Triangle Park, NC. February 1979.
A.16	Acurex/EPA/DOE	Acurex Corporation. Coal-Oil Mixture Combustion in an Industrial Steam Generator at Lorillard, a Division of Loews Theatres, Inc.; Danville, Virginia. Monthly Progress Report. DOE Contract EF-77-C-01-2563. October 1977.
A.17	Electric Power Development Company (Japan)	Nakabayashi, Y. and D. J. Lin. "Fine and Coarse Coal-Oil Mixture Combustion Tests of an Air Burner in Japan." (2nd Symposium Proceedings) November 1979.
A.18	Mitsubishi Heavy Industries, LTD. (Japan)	Takabashi, Y. et al. "Basic Studies on COM Combustion." 2nd Symposium Proceedings). November 1979.
A.19	Brookhaven National Laboratory	Rose, J. M. et al. "Performance Tests of Ultra-Fine Grind Coal-Oil Mixtures in a 150 hp Boiler". (3rd Symposium Proceedings). April 1981.
A.20	CoaLiquid, Inc. (and McDonnell Douglas Corp.)	Hawkins, G. T. "Commercial COM Operating Experience." (3rd Symposium Proceedings). April 1981.
A.21	BP Research Centre (England)	Veal, C. J. et al. "Stable Coal/Fuel Oil Dispersions." (2nd Symposium Proceedings). November 1979.
A.22	BP Research Centre (England)	Wall, D. R. "The Handling and Combustion of Stable Coal/Fuel Oil Dispersions." (3rd Symposium Proceedings). April 1981.

APPENDIX B

DEVELOPMENT OF EMISSION CONTROL COSTS

This Appendix contains information used in developing the emission control costs presented in Chapter 5. Section B.1 deals with boiler-related parameters impacting the control costs. Section B.2 presents the emission control equipment specifications used to develop control costs. Finally, Section B.3 provides documentation of the unit costs used to calculate labor, electricity, chemicals, maintainence and waste disposal costs. Detailed equations used to calculate the new system costs ($1978) (except for dry injection) can be found in Reference B-1. Dry injection costs were based on information in Reference B-2.

B-1 BOILER-RELATED PARAMETERS

Table B-1 shows the hypothetical ultimate analysis of the COM fuels used in this study. Based on these fuel compositions and an excess air level of 25 percent, the following flue gas flows were calculated:

COM Fuel	Gas flow @ 200°C (400°F) [actual ft^3/Btu of fuel burned]
A-1	0.0215
A-2	0.0214
A-3	0.0215
A-4	0.0214

Thus, based on a gas flow rate of 0.0214 actual ft^3/Btu of fuel burned (at 25 percent excess air, 400°F) the flue gas flows to be treated for the boiler sizes examined in this study are:

Boiler Size MW(10^6 Btu/hr)	Flue gas flow (400°F, 25% excess air)	
	m^3/second	acfm
8.8 (30)	5.0	10,700
73 (250)	42.1	89,300
205 (700)	118	250,000

TABLE B-1. ULTIMATE ANALYSIS OF COM FUELS

Fuel	Composition, % by weight							HHV (Btu/lb)
	Moisture	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
A-1 Eastern low ash low sulfur and low sulfur oil	1.31	83.42	7.35	0.89	2.59	0.97	3.48	16,150
A-2 Eastern low ash low sulfur and high sulfur oil	1.31	82.43	7.35	0.89	2.59	1.95	3.48	16,150
B-1 Eastern high ash high sulfur and low sulfur oil	4.44	76.50	7.22	0.8	3.43	2.29	5.34	15,150
B-2 Eastern high ash high sulfur and high sulfur oil	4.44	75.51	7.22	0.8	3.43	3.27	5.34	15,150

B.2 CONTROL EQUIPMENT SPECIFICATIONS

Tables B-2 through B-6 show the specifications for the following emission control equipment, respectively:

- Electrostatic precipitator,
- Fabric filter,
- Dual alkali venturi scrubber (SO_2/PM removal)
- Spray drying, and
- Dry injection.

These specifications were used as the basis for developing the emission control costs.

B.3 UNIT COSTS

Table B-7 shows the unit costs for utilities, chemicals, labor, and waste disposal (off-site disposal). The 1978 costs shown in Table B-7 were updated to $1981 as discussed in Chapter 5.

TABLE B-2. ELECTROSTATIC PRECIPITATOR EQUIPMENT SPECIFICATIONS

Equipment Description:	Cold-side ESP containing compartmented electrical units cleaned by mecahnical rappers
Cost Analysis Includes:	Fan and damper, ducting; ESP plates, wires, rappers, transformers, rectifiers and controls, ESP chamber
Specifications:	Specific collection area (SCA) = 39 $m^2/(m^3/s)$ (198 ft^2/1000 acfm) for Coal A 35 $m^2/(m^3/s)$ (175 ft^2/1000 acfm) for Coal B System pressure drop = 0.13 kPa(0.5 inches water column) Induced draft fan Design gas velocity = 1.5 to 1.8 m/s (5 to 6 ft/s) Ductwork - 61 m (200 ft) long

TABLE B-3. FABRIC FILTER EQUIPMENT SPECIFICATIONS

Equipment Description -	Compartmented modules cleaned by reversing the air flow
Cost Analysis Includes -	Fan and damper, ducting, filter bags, steel structural supports, and controls
Specifications -	Air-to-cloth ratio (A/C) = 2/1
	Pressure drop = 1.5 kPa (6" water column)
	Bags - Teflon coated fiberglass with a 2 year life
	Induced draft fan
	Ductwork - 61 meters (200 ft) long

TABLE B-4. DUAL ALKALI/VENTURI SCRUBBER EQUIPMENT SPECIFICATION

Equipment Description:	Variable-throat venturi SO_2 absorber, and sodium sorbent recovery reactor. Scrubber preceeded by mechanical collector.
Cost Analysis includes:	Raw materials handling and preparation, venturi scrubber, mechanical collector, reactor, clarifier, vacuum filter, holding tanks, pumps, fan, pipe, ductwork and controls.
Specifications:	Gas pressure drop = 5kPa (20" H_2O) L/G = 1.3 l/m^3 (10 gal/1000 ft^3) Scrubber liquor = 5% dissolved solids by weight Scrubber liquor pH = 6 to 8 Stainless steel construction Scrubber sludge = 60% solids

TABLE B-5. LIME SPRAY DRYER EQUIPMENT SPECIFICATIONS

Equipment Description:	Spray dryer and fabric filter system
Cost analysis includes:	Spray dryer, fabric filter, fan, ductwork, sorbent preparation and handling equipment, pumps and pipes (fabric filter specifications in Table B-2)
Specifications:	L/G = 0.04 $1/m^3$ (0.3 gal/1000 ft^3) Gas pressure drop = 1.5 kPa (6" H_2O) Flue gas residence time = 10 seconds Spray dryer outlet temperature = 80°C (175°F)

TABLE B-6. DRY INJECTION EQUIPMENT SPECIFICATIONS

Equipment Description:	Pneumatic sorbent injection and fabric filter system.
Cost analysis system:	Baghouse and auxiliaries, induced draft fans, 2 sorbent hoppers, sorbent conveyor, 4 rotary feeders and 2 blowers.
Specifications:	Baghouse operated for 72 minutes between cleanings. Filter bags are precoated with 20% of the total required nahcilite feed. Nahcolite was assumed to contain 70% $NaHCO_3$.

TABLE B-7. UNIT COSTS USED IN CALCULATIONS[a]

Utilities	
Electricity	\$0.0258/kWh
Water	\$0.04/m^3 (\$0.15/10^3 gal)
Steam	\$3.01/GJ (\$3.5/10^3 lb)
Raw Material	
Na_2CO_3	\$0.099/kg (\$90/ton)
Lime	\$0.039/kg (\$35/ton)
Limestone	\$0.009/kg (\$8/ton)
Nahcolite	\$0.042/kg (\$38/ton)
Labor	
Direct Labor	\$12.02/man-hour
Supervision	\$15.63/man-hour
Maintenance Labor	\$14.63/man-hour
Waste Disposal (Off-site landfill)	
Solids (Ash, Spray Dried Solids)	\$0.166/kg (\$15/ton)
Sludge	\$0.0166/kg (\$15/ton)

[a] All costs in 1978 \$.

B.4 REFERENCES

B.1 Jennings, M. S. and M. E. Kelly. (Radian Corporation). Costs of Sulfur Dioxide and Particulate Matter Emission Controls for Coal- and Oil-Fired Industrial Boilers. EPA Contract No. 68-02-3058. Prepared for U. S. Environmental Protection Agency. Research Triangle Park, NC. September 1981. Volumes I and II.

B.2 Genco, J. M., et al. "The Use of Nahcolite Ore and Bag Filters for Sulfur Dioxide Emission Control" In: Journal of the Air Pollution Control Association. 25(12):1244-1253. December 1975. [Costs were scaled down from utility size and updated from $1973 to $1981.]

APPENDIX C

ABBREVIATIONS

AA	Atomic absorption
BOOS	Burners out of service
CAA	Clean Air Act
CFR	Capital Recovery Factor
CLM	Coal-liquid mixture(s)
COM	Coal-oil mixture(s)
COW	Coal-oil-water mixture(s)
CWM	Coal-water mixture(s)
DOE	U. S. Department of Energy
EPA	U. S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
FGR	Flue gas recirculation
FGT	Flue gas treatment
HHV	Higher heat value
HSE	High Sulfur Eastern
LEA	Low excess air
L/G	Liquid-to-gas ratio
LSE	Low Sulfur Eastern
LSW	Low Sulfur Western
MSHA	Mine Safety and Health Administration
MW	Megawatt
NA	Nonattainment
NAA	Neutron Activation Analysis
NAAQS	National Ambient Air Quality Standards
NH_3	Ammonia
NO_x	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operation and Maintenance
OFA	Overfire air
OSHA	Occupational Safety and Health Administration

PETC	Pittsburgh Energy Technology Center
PCC	Physical coal cleaning
PM	Particulate matter
POM	Polynuclear Organic Material
PSD	Prevention of significant deterioration
ROM	Run-of-mine
SC	Staged combustion
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide

APPENDIX D

CONVERSION FACTORS

SI UNITS TO ENGLISH AND METRIC UNITS

To Convert From	To	Multiply By
in	cm	2.540
in^2	cm^2	6.452
ft	m	0.3048
ft^2	m^2	0.09290
ft^3	m^3	0.02832
lb	kg	0.4536
lb/hr	Mg/s	0.1260
$lb/10^6$ Btu	ng/J	430
g/Mcal	ng/J	239
Btu	J	1054
Btu/lb	J/kg	0.002324
Btu/hr	W	0.2929
J/sec	W	1.000
J/hr	W	3600
Btu/ft/hr	W/m	0.9609
Btu/ft/hr	J/hr/m	3459
$Btu/ft^2/hr$	W/m^2	3.152
$Btu/ft^2/hr$	$J/hr/m^2$	11349
$Btu/ft^3/hr$	W/m^3	10.34
$Btu/ft^3/hr$	$J/hr/m^3$	37234
psia	Pa	6895
"H_2O	Pa	249.1
Rankine	Celsius	C = 5/9R-273
Fahrenheit	Celsius	C = 5/9(F-32)
Celsius	Kelvin	K = C+273
Rankine	Kelvin	K = 5/9R

COAL FUEL ONLY

ppm @ 3% O_2 (SO_2)	ng/J	0.851
ppm @ 3% O_2 (SO_3)	ng/J	1.063
ppm @ 3% O_2 (NO)	ng/J	0.399
ppm @ 3% O_2 (NO_2)	ng/J	0.611
ppm @ 3% O_2 (CO)	ng/J	0.372
ppm @ 3% O_2 (CH_4)	ng/J	0.213

SI UNITS TO ENGLISH AND METRIC UNITS

To Convert From	To	Multiply By
cm	in	0.3937
cm^2	in^2	0.1550
m	ft	3.281
m^2	ft^2	10.764
m^3	ft^3	35.315
kg	lb	2.205
Mg/s	lb/hr	7.937
ng/J	$lb/10^6$ Btu	0.00233
ng/J	g/Mcal	0.00418
J	Btu	0.000948
J/kg	Btu/lb	4.303
J/hr/m	Btu/ft/hr	0.000289
$J/hr/m^2$	$Btu/ft^2/hr$	0.0000881
$J/hr/m^3$	$Btu/ft^3/hr$	0.0000269
W	Btu/hr	3.414
W	J/hr	0.000278
W/m	Btu/ft/hr	1.041
W/m^2	$Btu/ft^2/hr$	0.317
W/m^3	$Btu/ft^3/hr$	0.967
Pa	psia	0.000145
Pa	"H_2O	0.004014
Kelvin	Fahrenheit	F = 1.8K-460
Celsius	Fahrenheit	F = 1.8C+32
Fahrenheit	Rankine	R = F+460
Kelvin	Rankine	R = 1.8K

COAL FUEL ONLY

ng/J	ppm @ 3% O_2 (SO_2)	1.18
ng/J	ppm @ 3% O_2 (SO_3)	0.941
ng/J	ppm @ 3% O_2 (NO)	2.51
ng/J	ppm @ 3% O_2 (NO_2)	1.64
ng/J	ppm @ 3% O_2 (CO)	2.69
ng/J	ppm @ 3% O_2 (CH_4)	4.69

SI PREFIXES

Multiplication Factor	Prefix	SI Symbol
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto*	h
10^{1}	deka*	da
10^{-1}	deci*	d
10^{-2}	centi*	c
10^{-3}	milli	m
10^{-6}	micro	μ
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

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*Not recommended but occasionally used.